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Entergy

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Fred Dacimo
Vice President
License Renewal

December 18, 2007

Re: Indian Point Units 2 & 3
Docket Nos. 50-247 & 50-286
NL-07-153

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

SUBJECT: Entergy Nuclear Operations Inc.
Indian Point Nuclear Generating Unit Nos. 2 & 3
Docket Nos. 50-247 and 50-286
Amendment 1 to License Renewal Application (LRA)

REFERENCES:

1. Entergy Letter dated April 23, 2007, F. R. Dacimo to Document Control Desk, "License Renewal Application" (NL-07-039)
2. Entergy Letter dated April 23, 2007, F. R. Dacimo to Document Control Desk, "License Renewal Application Boundary Drawings (NL-07-040)
3. Entergy Letter dated April 23, 2007, F. R. Dacimo to Document Control Desk, "License Renewal Application Environmental Report References (NL-07-041)
4. Entergy Letter dated October 11, 2007, F. R, Dacimo to Document Control Desk, "License Renewal Application (LRA)" (NL-07-124)
5. Entergy Letter November 14, 2007, F. R, Dacimo to Document Control Desk, "Supplement to License Renewal Application (LRA) Environmental Report References" (NL-07-133)

Dear Sir or Madam:

In the referenced letters, Entergy Nuclear Operations, Inc. applied for renewal of the Indian Point Energy Center operating license.

This letter contains Amendment 1 of the License Renewal Application (LRA), which consists of four attachments. Attachment 1 consists of an amendment to the LRA. Attachment 2 consists of a revision to the list of regulatory commitments associated with the LRA. Attachment 3

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consists of the questions and provides the responses to the questions raised by the NRC team during the Aging Management Programs (AMP) portion of the LRA. Attachment 4 consists of the questions and provides the responses to the questions raised by the NRC team during the Aging Management Reviews (AMR) portion of the LRA.

This letter contains no new commitments. If you have any questions, or require additional information, please contact Mr. Robert Walpole at 914-734-6710.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 12/18/07.

Sincerely,

Fred R. Dacimo
Vice President
License Renewal

Attachments:

1. License Renewal Application, Amendment 1
2. List of Regulatory Commitments, Revision 1
   (This revision supersedes the revision submitted in letter NL-07-039 dated 4-23-2007)
3. AMP Database Report, Revision 1
   (This revision supersedes the revision submitted in letter NL-07-124 dated 10-11-2007)
4. AMR Database Report, Revision 0

cc: Mr. Samuel J. Collins, Regional Administrator, NRC Region I
Mr. Kenneth Chang, NRC Branch Chief, Engineering Review Branch I
Mr. Bo M. Pham, NRC Environmental Project Manager
Mr. John Boska, NRR Senior Project Manager
Mr. Paul Eddy, New York State Department of Public Service
NRC Resident Inspector's Office
Mr. Paul D. Tonko, President, New York State Energy, Research, & Development Authority

ATTACHMENT 1 TO NL-07-153

License Renewal Application, Amendment 1

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

License Renewal Application

Amendment 1

Audit Item 1

The alternate or second GDC-17 offsite power source was not shown in LRA Figures 2.5-2 and 2.5-3. These figures were revised in letter NL-07-138 to the NRC dated 11/16/07.

Audit Item 26

The following is an element-by-element comparison of the IPEC Containment Inservice Inspection (CII) Program to NUREG-1801 AMP XI.S1, ASME Section XI, Subsection IWE. It is followed by an element-by-element comparison of the CII Program to NUREG-1801 AMP XI.S2, ASME Section XI, Subsection IWL.

Comparison to NUREG-1801 AMP XI.S1, ASME Section XI, Subsection IWE;

1. Scope of Program

NUREG-1801 XI.S1 Scope of Program

"Subsection IWE-1000 specifies the components of steel containments and steel liners of concrete containments within its scope. The components within the scope of Subsection IWE are Class MC pressure-retaining components (steel containments) and their integral attachments; metallic shell and penetration liners of Class CC containments and their integral attachments; containment seals and gaskets; containment pressure-retaining bolting; and metal containment surface areas, including welds and base metal. The concrete portions of containments are inspected in accordance with Subsection IWL.

Subsection IWE exempts the following from examination:

(1) Components that are outside the boundaries of the containment as defined in the plant-specific design specification;

(2) Embedded or inaccessible portions of containment components that met the requirements of the original construction code of record;

(3) Components that become embedded or inaccessible as a result of vessel repair or replacement, provided IWE-1232 and IWE-5220 are met; and

(4) Piping, pumps, and valves that are part of the containment system or that penetrate or are attached to the containment vessel (governed by IWB or IWC).

10 CFR 50.55a(b)(2)(ix) specifies additional requirements for inaccessible areas. It states that the licensee is to evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such

inaccessible areas. Examination requirements for containment supports are not within the scope of Subsection IWE."

Comparison to IPEC Scope of Program

The Containment Inservice Inspection Program, under ASME Section XI, Subsection IWE manages aging effects for the containment liners and integral attachments including connecting penetrations and parts forming the leak tight boundary. Visual inspections for IWE monitor loss of material of the steel containment liners and their integral attachments; containment hatches and airlocks; moisture barriers; and pressure-retaining bolting by inspecting surfaces for evidence of flaking, blistering, peeling, discoloration, and other signs of distress.

The CII program specifies that an evaluation of inaccessible areas will be performed if conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas.

IP2 and IP3 containments are reinforced concrete structures. Therefore, IWE requirements pertaining to steel containment shells and their integral attachments do not apply.

NUREG -1801 states that containment seals and gaskets are within the scope of the program. However, it appears that this statement in NUREG-1801, Rev. 1, XI.S1, Scope of Program is incorrect because ASME Section XI, 2001 edition including the 2002 and 2003 Addenda does not include containment seals and gaskets. It appears that the phrase "containment seals and gaskets" was not removed when the ASME code version cited in NUREG-1801 was changed. Consistent with ASME Section XI, 2001 edition including the 2002 and 2003 Addenda, containment seals and gaskets are not included in the IPEC CII Program. The leak tight integrity of containment seals and gaskets is determined by the Containment Leak Rate Program.

The IPEC scope of program is consistent with NUREG-1801.

2. Preventive Action

NUREG-1801 XI.S1 Preventive Action

"No preventive actions are specified; Subsection IWE is a monitoring program."

Comparison to IPEC Preventive Actions

The IPEC CII Program is a monitoring program that does not include preventive actions.

IPEC preventive actions are consistent with NUREG-1801.

3. Parameters Monitored or Inspected

NUREG-1801 XI.S1 Parameters Monitored or Inspected

"Table IWE-2500-1 specifies seven categories for examination. The categories, parts examined, and examination methods are presented in the following table. The first six examination categories (E-A through E-G) constitute the ISI requirements of IWE. Examination category E-P references 10 CFR Part 50, Appendix J leak rate testing. Appendix J leak rate testing is evaluated as a separate AMP for license renewal in XI.S4."

CATEGORY	PARTS EXAMINED	EXAMINATION METHOD[a]
E-A	Containment surfaces	General visual, visual VT-3
E-B[b]	Pressure retaining welds	Visual VT-1
E-C	Containment surfaces requiring augmented examination	Visual VT-1, volumetric
E-D	Seals, gaskets, and moisture barriers	Visual VT-3
E-F[b]	Pressure retaining dissimilar metal welds	Surface
E-G	Pressure retaining bolting	Visual VT-1, bolt torque or tension test
E-P	All pressure-retaining components (pressure retaining boundary, penetration testing) bellows, airlocks, seals, and gaskets)	10 CFR Part 50, Appendix J (containment leak rate)

a. The applicable examination method (where multiple methods are listed) depends on the particular subcategory within each category.
b. These two categories are optional, in accordance with 10 CFR 50.55a(b)(2)(ix)(C).

Table IWE-2500-1 references the applicable section in IWE-3500 that identifies the aging effects that are evaluated. The parameters monitored or inspected depend on the particular examination category. For Examination Category E-A, as an example, metallic surfaces (without coatings) are examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities. For Examination Category E-D, seals, gaskets, and moisture barriers are examined for wear, damage, erosion, tear, surface cracks, or other defects that may violate the leak-tight integrity."

Comparison to IPEC Parameters Monitored and Inspected

Visual inspections for IWE monitor loss of material of the steel containment liners and attachments by inspecting the surface for evidence of flaking, blistering, peeling, discoloration, and other signs of distress.

The primary inspection method for the steel containment liner and its integral attachments is general visual examination. Containment surfaces, moisture barriers and pressure retaining bolting receive a general visual or VT-3 examination. Painted or coated areas are examined for evidence of flaking, blistering, peeling, and discoloration. Non-coated areas are examined for evidence of cracking, discoloration, wear, pitting, corrosion, gouges, and surface irregularities. Moisture barriers are examined for wear, damage, erosion, tears, surface cracks, or other defects that may violate the leak-tight integrity. Containment surfaces requiring augmented examination receive an augmented visual or volumetric examination.

In accordance with the option provided by 10 CFR 50.55a(b)(2)(ix)(C), the examinations of categories E-B and E-F are not performed.

The Containment Leak Rate Program includes all primary containment pressure-retaining components as described in 10 CFR Part 50, Appendix J.

NUREG-1801 indicates that containment seals and gaskets are visually inspected. However, it appears that the table in NUREG-1801, Rev. 1, XI.S1, Parameters Monitored or Inspected is incorrect because ASME Section XI, 2001 edition including the 2002 and 2003 Addenda does not include containment seals and gaskets. It appears that the inspection of seals and gaskets was not removed when the ASME code version cited in NUREG-1801 was changed. Consistent with ASME Section XI, 2001 edition including the 2002 and 2003 Addenda, containment seals and gaskets are not inspected in the CII Program. The leak tight integrity of containment seals and gaskets is determined by the Containment Leak Rate Program.

NUREG-1801 indicates that pressure retaining bolting is subject to torque or tension testing. However, it appears that the table in NUREG-1801, Rev. 1, XI.S1, Parameters Monitored or Inspected is incorrect because ASME Section XI, 2001 edition including the 2002 and 2003 Addenda does not include torque or tension test of pressure retaining bolting. It appears that the torque or tension test of pressure retaining bolting was not removed when the ASME code version cited in NUREG-1801 was changed. Consistent with ASME Section XI, 2001 edition including the 2002 and 2003 Addenda, bolt preload is not checked by either a torque or tension test in the CII program. The leak tight integrity of pressure retaining bolted joints is determined by the Containment Leak Rate Program.

IPEC parameters monitored or inspected are consistent with NUREG-1801.

4. Detection of Aging Effects

NUREG-1801 XI.S1 Detection of Aging Effects

"The frequency and scope of examination specified in 10 CFR 50.55a and Subsection IWE ensure that aging effects would be detected before they would compromise the design-basis requirements. As indicated in IWE-2400, inservice examinations and pressure tests are performed in accordance with one of two inspection programs, A or B, on a specified schedule. Under Inspection Program A, there are four inspection intervals (at 3, 10, 23, and 40 years) for which 100% of the required examinations must be completed. Within each interval, there are various inspection periods for which a certain percentage of the examinations are to be performed to reach 100% at the end of that interval. In addition, a general visual examination is performed once each inspection period. After 40 years of operation, any future examinations will be performed in accordance with Inspection Program B. Under Inspection Program B, starting with the time the plant is placed into service, there is an initial inspection interval of 10 years and successive inspection intervals of 10 years each, during which 100% of the required examinations are to be completed. An expedited examination of containment is required by 10 CFR 50.55a in which an inservice (baseline) examination specified for the first period of the first inspection interval for containment is to be performed by September 9, 2001. Thereafter, subsequent examinations are performed every 10 years from the baseline examination. Regarding the extent of examination, all accessible surfaces receive a visual examination such as General Visual, VT-1, or VT-3 (see table in item 3 above). IWE-1240 requires augmented examinations (Examination Category E-C) of containment surface areas subject to degradation. A VT-1 visual examination is performed for areas accessible from both sides, and volumetric (ultrasonic thickness measurement) examination is performed for areas accessible from only one side."

Comparison to IPEC Detection of Aging Effects

The IPEC CII program implements Inspection Program B. An inservice (baseline) examination was performed and subsequent examinations are performed every 10 years from the baseline examination.

As described in Element 3, Parameters Monitored or Inspected, with the exception of seals and gaskets, all accessible surfaces receive a visual examination. The leak tight integrity of containment seals and gaskets is determined by the Containment Leak Rate Program.

Augmented examinations in the CII Program are performed for containment surfaces subject to degradation. Visual examination is performed for areas accessible from both sides and volumetric examination is performed for areas accessible from only one side.

IPEC detection of aging effects is consistent with NUREG-1801.

5. Monitoring and Trending

NUREG-1801 XI.S1 Monitoring and Trending

"With the exception of inaccessible areas, all surfaces are monitored by virtue of the examination requirements on a scheduled basis. When component examination results require evaluation of flaws, evaluation of areas of degradation, or repairs, and the component is found to be acceptable for continued service, the areas containing such flaws, degradation, or repairs shall be reexamined during the next inspection period, in accordance with Examination Category E-C. When these reexaminations reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods, these areas no longer require augmented examination in accordance with Examination Category E-C.

IWE-2430 specifies that (a) examinations performed during any one inspection that reveal flaws or areas of degradation exceeding the acceptance standards are to be extended to include an additional number of examinations within the same category approximately equal to the initial number of examinations, and (b) when additional flaws or areas of degradation that exceed the acceptance standards are revealed, all of the remaining examinations within the same category are to be performed to the extent specified in Table IWE-2500-1 for the inspection interval. Alternatives to these examinations are provided in 10 CFR 50.55a(b)(2)(ix)(D)."

Comparison to IPEC Monitoring and Trending

As described in Element 3, Parameters Monitored or Inspected, with the exception of seals and gaskets, all accessible surfaces receive a visual examination.

Augmented examinations are required when component examinations result in an evaluation of flaws, or areas of degradation, and the components are found acceptable for continued operation. Surfaces requiring augmented examination receive an examination in the next inspection period.

When flaws or areas of degradation exceed acceptance standards, the IPEC CII program follows the alternative provided in 10 CFR 50.55a(b)(2)(ix)(D). Specifically, an evaluation is performed to determine whether additional component examinations are required. For each flaw or area of degradation identified which exceeds acceptance standards, the following information is included in a report.

- A description of each flaw or area, including the extent of degradation, and the conditions that led to the degradation
- The acceptability of each flaw or area, and the need for additional examinations to verify that similar degradation does not exist in similar components
- A description of necessary corrective actions
- The number and type of additional examinations to ensure detection of similar degradation in similar components

NUREG -1801 indicates that repaired areas should be reexamined during the next inspection period. However, it appears that this statement in NUREG-1801, Rev. 1, XI.S1, Monitoring and Trending is incorrect because ASME Section XI, 2001 edition including the 2002 and 2003 Addenda does not require reexamination of repaired areas. It appears that reexamination of repaired areas was not removed when the ASME code version cited in NUREG -1801 was changed. Consistent with ASME Section XI, 2001 edition including the 2002 and 2003 Addenda, the CII program does not include provisions for successive examination of repaired areas.

NUREG -1801 indicates that, when reexaminations reveal augmented examination areas remain essentially unchanged for three consecutive inspection periods; these areas no longer require augmented examination in accordance with Examination Category E-C. However, it appears that this statement in NUREG -1801, Rev. 1, XI.S1, Monitoring and Trending is incorrect because ASME Section XI, 2001 edition including the 2002 and 2003 addenda allows examinations to cease when the augmented examination area remains essentially unchanged for one inspection period. It appears that this statement was not changed when the ASME code version cited in NUREG -1801 was changed. Consistent with ASME Section XI, 2001 edition including the 2002 and 2003 Addenda, the CII program allows examinations to cease when the augmented examination area remains essentially unchanged for one inspection period.

IPEC monitoring and trending is consistent with NUREG-1801.

6. Acceptance Criteria

NUREG-1801 XI.S1 Acceptance Criteria

"IWE-3000 provides acceptance standards for components of steel containments and liners of concrete containments. Table IWE-3410-1 presents criteria to evaluate the acceptability of the containment components for service following the preservice examination and each inservice examination. This table specifies the acceptance standard for each examination category. Most of the acceptance standards rely on visual examinations. Areas that are suspect require an engineering evaluation or require correction by repair or replacement. For some examinations, such as augmented examinations, numerical values are specified for the acceptance standards. For the containment steel shell or liner, material loss exceeding 10% of the nominal containment wall thickness, or material loss that is projected to exceed 10% of the nominal containment wall thickness before the next examination, are documented. Such areas are to be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122."

Comparison to IPEC Acceptance Criteria

Results are compared, as appropriate, to baseline data, other previous test results, and acceptance criteria of ASME Section XI, Subsection IWE-3000 for evaluation of any evidence of degradation.

The acceptance standards rely on visual examinations. Areas that are suspect require an engineering evaluation or require correction by repair or replacement. For some examinations, such as augmented examinations, numerical values are specified for the acceptance standards. For the containment steel shell or liner, material loss exceeding 10% of the nominal containment wall thickness, or material loss that is projected to exceed 10% of the nominal containment wall thickness before the next examination, are documented. Such areas are accepted by engineering evaluation or corrected by repair or replacement.

IPEC acceptance criteria are consistent with NUREG-1801.

7. Corrective Actions

NUREG-1801 XI.S1 Corrective Actions

"Subsection IWE states that components whose examination results indicate flaws or areas of degradation that do not meet the acceptance standards listed in Table-3410-1 are acceptable if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no effect on the structural integrity of the containment. Except as permitted by 10 CFR 50.55a(b)(ix)(D), components that do not meet the acceptance standards are subject to additional examination requirements, and the components are repaired or replaced to the extent necessary to meet the acceptance standards of IWE-3000. For repair of components within the scope of Subsection IWE, IWE-3124 states that repairs and reexaminations are to comply with IWA-4000. IWA-4000 provides repair specifications for pressure retaining components including metal containments and metallic liners of concrete containments. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions."

Comparison to IPEC Corrective Actions

ASME Section XI, Subsection IWE states that components whose examination results indicate flaws or areas of degradation that do not meet the acceptance standards are acceptable if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no effect on the structural integrity of the containment. Except as permitted by 10 CFR 50.55a(b)(ix)(D), components that do not meet the acceptance standards are subject to additional examination requirements, and the components are repaired or replaced to the extent necessary to meet the acceptance standards.

Repair and replacement activities comply with IWA-4000.

IPEC corrective actions are in accordance with 10 CFR 50 Appendix B.

IPEC corrective actions are consistent with NUREG-1801.

8. Confirmation Process

NUREG-1801 XI.S1 Confirmation Process

"When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. If the evaluation determines that repair or replacement is necessary, Subsection IWE specifies confirmation that appropriate corrective actions have been completed and are effective.

Subsection IWE states that repairs and reexaminations are to comply with the requirements of IWA-4000. Reexaminations are conducted in accordance with the requirements of IWA-2200, and the recorded results are to demonstrate that the repair meets the acceptance standards set forth in Table IWE-3410-1. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process."

Comparison to IPEC Confirmation Process

This element is discussed in Section B.0.3 of the LRA, which indicates that the IPEC confirmation process is in accordance with 10 CFR 50 Appendix B and consistent with NUREG -1801 (Volume 2 Appendix A, 2nd bullet).

When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. If the evaluation determines that repair or replacement is necessary, reexamination confirms that appropriate corrective actions have been completed and are effective.

Repair and replacement activities comply with IWA-4000 and associated reexaminations are conducted in accordance with IWA-2200. The recorded results demonstrate that the repair meets the acceptance standards of Table IWE-3410-1 (IP2) or IWE-3500 (IP3).

NUREG-1801 indicates that reexamination results are to demonstrate that the repair meets the acceptance standards set forth in Table IWE-3410-1. IP2 reexamination results are compared with the acceptance standards of Table IWE-3410-1, while IP3 reexamination results are compared with the acceptance standards of IWE-3500. The version of ASME Section XI currently in use at IP2 (1992 Edition with 1992 Addenda) contains Table IWE-3410-1. However, the version of ASME Section XI currently in use at IP3 (1998 Edition, no Addenda) as well as the version cited in NUREG-1801 Rev. 1, XI.S1 (2001 edition with 2002 and 2003 Addenda) do not contain Table IWE-3410-1. In these versions of the code, acceptance standards are contained in IWE-3500.

The IPEC confirmation process is consistent with NUREG-1801.

9. Administrative Controls

NUREG-1801 XI.S1 Administrative Controls

"IWA-6000 provides specifications for the preparation, submittal, and retention of records and reports. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls."

Comparison to IPEC Administrative Controls

This element is discussed in Section B.0.3 of the LRA, which indicates that IPEC administrative controls are in accordance with 10 CFR 50 Appendix B and consistent with NUREG-1801 (Volume 2 Appendix A, 2nd bullet).

Preparation, submittal, and retention of records and reports are in accordance with IWA-6000 or alternatives approved in 10 CFR50.55a.

IPEC administrative controls are consistent with NUREG-1801.

10. Operating Experience

NUREG-1801 XI.S1 Operating Experience

"ASME Section XI, Subsection IWE was incorporated into 10 CFR 50.55a in 1996. Prior to this time, operating experience pertaining to degradation of steel components of containment was gained through the inspections required by 10 CFR Part 50, Appendix J and ad hoc inspections conducted by licensees and the Nuclear Regulatory Commission (NRC). NRC Information Notice (INs) 86-99, 88-82 and 89-79 described occurrences of corrosion in steel containment shells. NRC Generic Letter (GL) 87-05 addressed the potential for corrosion of boiling water reactor (BWR) Mark I steel drywells in the "sand pocket region." More recently, NRC IN 97-10 identified specific locations where concrete containments are susceptible to liner plate corrosion. The program is to consider the liner plate and containment shell corrosion concerns described in these generic communications. Implementation of the ISI requirements of Subsection IWE, in accordance with 10 CFR 50.55a, is a necessary element of aging management for steel components of steel and concrete containments through the period of extended operation."

Comparison to IPEC Operating Experience

Results of the IWE containment inspection performed at IP2 in 2004 were satisfactory.

Minor surface corrosion was detected during an IWE containment inspection at IP3 in 2005, which was classified as "acceptable" under the program definitions.

A self-assessment of the CII program was completed in October 2004. All findings from earlier EPRI assessments of the program were found to be evaluated and the recommendations implemented.

The containment shell corrosion concerns described in USNRC IN 97-10, Liner Plate Corrosion in Concrete Containments, have been considered in the CII program.

IPEC operating experience is consistent with NUREG-1801.

Comparison to NUREG-1801 AMP XI.S2, ASME Section XI, Subsection IWL;

1. Scope of Program

NUREG 1801 XI.S2 Scope of Program

"Subsection IWL-1000 specifies the components of concrete containments within its scope. The components within the scope of Subsection IWL are reinforced concrete and unbonded post-tensioning systems of Class CC containments, as defined by CC-1000. Subsection IWL exempts from examination portions of the concrete containment that are inaccessible (e.g., concrete covered by liner, foundation material, or backfill, or obstructed by adjacent structures or other components).

10 CFR 50.55a(b)(2)(viii) specifies additional requirements for inaccessible areas. It states that the licensee is to evaluate the acceptability of concrete in inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. Steel liners for concrete containments and their integral attachments are not within the scope of Subsection IWL, but are included within the scope of Subsection IWE."

Comparison to IPEC Scope of Program

The components addressed within the Containment Inservice Inspection (CII) Program are those specified in Subsection IWL-1000.

In accordance with 10 CFR 50.55a(b)(2)(viii), the CII program specifies that an evaluation of inaccessible areas will be performed if conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas.

IP2 and IP3 containments are reinforced concrete structures that do not utilize a post-tensioning system. Therefore, IWL requirements pertaining to post-tensioning and expansion of inspection scope do not apply.

IPEC scope of program is consistent with NUREG-1801.

2. Preventive Actions

NUREG-1801 XI.S2 Preventive Actions

"No preventive actions are specified; Subsection IWL is a monitoring program. If a coating program is currently credited for managing the effects of aging of concrete surfaces, then the program is to be continued during the period of extended operation."

Comparison to IPEC Preventive Actions

The CII Program is a monitoring program that does not include preventive actions. A coating program is not credited for managing the effects of aging of concrete surfaces.

IPEC preventive actions are consistent with NUREG-1801.

3. Parameters Monitored or Inspected

NUREG-1801 XI.S2 Parameters Monitored or Inspected

"Table IWL-2500-1 specifies two categories for examination of concrete surfaces: Category L-A for all concrete surfaces and Category L-B for concrete surfaces surrounding tendon anchorages. Both of these categories rely on visual examination methods. Concrete surfaces are examined for evidence of damage or degradation, such as concrete cracks. IWL-2510 specifies that concrete surfaces are examined for conditions indicative of degradation, such as those defined in ACI 201.1R-77. Table IWL-2500-1 also specifies Category L-B for test and examination requirements for unbonded post tensioning systems. Tendon anchorage and wires or strands are visually examined for cracks, corrosion, and mechanical damage. Tendon wires or strands are also tested for yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is tested by analysis for alkalinity, water content, and soluble ion concentrations."

Comparison to IPEC Parameters Monitored or Inspected

As specified in Table IWL-2500-1, Category L-A, visual inspections for IWL monitor concrete surfaces for conditions indicative of degradation, such as evidence of leaching, erosion, voids, scaling, spalls, corrosion, cracking, exposed reinforcing steel, and detached embedment. These conditions indicative of degradation are consistent with those described in ACI 201.1R-77.

As indicated in Element 1, Scope of Program, IP2 and IP3 containments are reinforced concrete structures that do not utilize a post-tensioning system. Therefore, IWL requirements pertaining to post-tensioning do not apply.

IPEC parameters monitored or inspected are consistent with NUREG-1801.

4. Detection of Aging Effects

NUREG-1801 XI.S2 Detection of Aging Effects

"The frequency and scope of examinations specified in 10 CFR 50.55a and Subsection IWL ensure that aging effects would be detected before they would compromise the design-basis requirements. The frequency of inspection is specified in IWL-2400. Concrete inspections are performed in accordance with Examination Category L-A. Under Subsection IWL, inservice inspections for concrete and unbonded post-tensioning systems are required at one, three, and five years following the structural integrity test. Thereafter, inspections are performed at five-year intervals. For sites with two plants, the schedule for inservice inspection is provided in IWL-2421. In the case of tendons, only a sample of the tendons of each tendon type requires examination at each inspection. The tendons to be examined during an inspection are selected on a random basis. Table IWL-2521-1 specifies the number of tendons to be selected for each type (e.g., hoop, vertical, dome, helical, and inverted U) for each inspection period. The minimum number of each tendon type selected for inspection varies from 2 to 4%. Regarding detection methods for aging effects, all concrete surfaces receive a visual VT-3C examination. Selected areas, such as those that indicate suspect conditions and areas surrounding tendon anchorages, receive a more rigorous VT-1 or VT-1C examination. Prestressing forces in sample tendons are measured. In addition, one sample tendon of each type is detensioned. A single wire or strand is removed from each detensioned tendon for examination and testing. These visual examination methods and testing would identify the aging effects of accessible concrete components and prestressing systems in concrete containments."

Comparison to IPEC Detection of Aging Effects

The primary inspection method for the concrete containment shell is a general visual examination in accordance with Examination Category L-A at the frequency specified in IWL-2400. Detailed visual examinations are performed to provide sufficient data to conduct an acceptance review when conditions exceeding the screening criteria are noted.

As indicated in Element 1, Scope of Program, IP2 and IP3 containments are reinforced concrete structures that do not utilize a post-tensioning system. Therefore, IWL requirements pertaining to post-tensioning do not apply.

IPEC detection of aging effects is consistent with NUREG-1801.

5. Monitoring and Trending

NUREG-1801 XI.S2 Monitoring and Trending

"Except in inaccessible areas, all concrete surfaces are monitored on a regular basis by virtue of the examination requirements. For prestressed containments, trending of prestressing forces in tendons is required in accordance with paragraph (b)(2)(viii) of 10 CFR 50.55a. In addition to the random sampling used for tendon examination, one tendon of each type is selected from the first-year inspection sample and designated as a common tendon. Each common tendon is then examined during each inspection. This procedure provides monitoring and trending information over the life of the plant. 10 CFR 50.55a and

Subsection IWL also require that prestressing forces in all inspection sample tendons be measured by lift-off tests and compared with acceptance standards based on the predicted force for that type of tendon over its life."

Comparison to IPEC Monitoring and Trending

Concrete surfaces are monitored on a regular basis by virtue of the examination requirements. Results are compared, as appropriate, to baseline data and other previous test results.

As indicated in Element 1, Scope of Program, IP2 and IP3 containments are reinforced concrete structures that do not utilize a post-tensioning system. Therefore, IWL requirements pertaining to post-tensioning do not apply.

IPEC monitoring and trending is consistent with NUREG-1801.

6. Acceptance Criteria

NUREG-1801 XI.S2 Acceptance Criteria

"IWL-3000 provides acceptance criteria for concrete containments. For concrete surfaces, the acceptance criteria rely on the determination of the "Responsible Engineer" (as defined by the ASME Code) regarding whether there is any evidence of damage or degradation sufficient to warrant further evaluation or repair. The acceptance criteria are qualitative; guidance is provided in IWL-2510, which references ACI 201.1R-77 for identification of concrete degradation. IWL-2320 requires that the Responsible Engineer be a registered professional engineer experienced in evaluating the inservice condition of structural concrete and knowledgeable of the design and construction codes and other criteria used in design and construction of concrete containments. Quantitative acceptance criteria based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R may also be used to augment the qualitative assessment of the responsible engineer. The acceptance standards for the unbonded post-tensioning system are quantitative in nature. For the post-tensioning system, quantitative acceptance criteria are given for tendon force and elongation, tendon wire or strand samples, and corrosion protection medium. 10 CFR 50.55a and Subsection IWL do not define the method for calculating predicted tendon prestressing forces for comparison to the measured tendon lift-off forces. The predicted tendon forces are to be calculated in accordance with Regulatory Guide 1.35.1, which provides an acceptable methodology for use through the period of extended operation."

Comparison to IPEC Acceptance Criteria

Visual inspections for IWL monitor concrete surfaces for conditions indicative of degradation, such as evidence of leaching, erosion, voids, scaling, spalls, corrosion, cracking, exposed reinforcing steel, and detached embedment. These conditions indicative of degradation are consistent with those described in ACI 201.1R-77. Results are compared, as appropriate, to baseline data, other previous test results, and acceptance criteria of ASME Section XI, Subsection IWL-3000 for evaluation of any evidence of degradation.

The Responsible Engineer is a registered professional engineer experienced in evaluating the inservice condition of structural concrete and knowledgeable of the design and construction codes and other criteria used in design and construction of concrete containments.

As indicated in Element 1, Scope of Program, IP2 and IP3 containments are reinforced concrete structures that do not utilize a post-tensioning system. Therefore, IWL requirements pertaining to post-tensioning do not apply.

IPEC acceptance criteria are consistent with NUREG-1801.

7. Corrective Actions

NUREG-1801 XI.S2 Corrective Actions

"Subsection IWL specifies that items for which examination results do not meet the acceptance standards are to be evaluated in accordance with IWL-3300 "Evaluation" and described in an engineering evaluation report. The report is to include an evaluation of whether the concrete containment is acceptable without repair of the item and if repair is required, the extent, method, and completion date of the repair or replacement. The report also identifies the cause of the condition and the extent, nature, and frequency of additional examinations. Subsection IWL also provides repair procedures to follow in IWL-4000. This includes requirements for the concrete repair, repair of reinforcing steel, and repair of the post-tensioning system. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions."

Comparison to IPEC Corrective Actions

Items with examination results that not meet the acceptance standards are described in an engineering evaluation report. The report includes a discussion of the cause of the condition that does not meet the acceptance standard and an evaluation of whether the concrete containment is acceptable without repair of the item. If repair is required, the extent, method, and completion date of the repair or replacement are included. The report also identifies the extent, nature, and frequency of additional examinations.

Repair and replacement activities comply with IWL-4000.

IPEC corrective actions are in accordance with 10 CFR 50 Appendix B.

As indicated in Element 1, Scope of Program, IP2 and IP3 containments are reinforced concrete structures that do not utilize a post-tensioning system. Therefore, IWL requirements pertaining to post-tensioning do not apply.

IPEC corrective actions are consistent with NUREG-1801.

8. Confirmation Process

NUREG-1801 Confirmation Process

"When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. As part of this evaluation, IWL-3300 specifies that the engineering evaluation report include the extent, nature, and frequency of additional examinations. IWL-4000 specifies the requirements for examination of areas that are repaired. Pressure tests following repair or modifications are in accordance with IWL-5000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process."

Comparison to IPEC Confirmation Process

This element is discussed in Section B.0.3 of the LRA, which indicates that the IPEC confirmation process is in accordance with 10 CFR 50 Appendix B and consistent with NUREG-1801 (Volume 2 Appendix A, 2nd bullet).

Items with examination results that not meet the acceptance standards are described in an engineering evaluation report. The report includes a discussion of the cause of the condition that does not meet the acceptance standard and an evaluation of whether the concrete containment is acceptable without repair of the item. If repair is required, the extent, method, and completion date of the repair or replacement are included. The report also identifies the extent, nature, and frequency of additional examinations.

Repair and replacement activities comply with IWL-4000. Pressure tests following repair or modifications are in accordance with IWL-5000.

The IPEC confirmation process is in accordance with 10 CFR 50 Appendix B.

The IPEC confirmation process is consistent with NUREG-1801.

9. Administrative Controls

NUREG-1801 Administrative Controls

"IWA-1400 specifies the preparation of plans, schedules, and inservice inspection summary reports. In addition, written examination instructions and procedures, verification of qualification level of personnel who perform the examinations, and documentation of a quality assurance program are specified. IWA-6000 specifically covers the preparation, submittal, and retention of records and reports. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls."

Comparison to IPEC Administrative Controls

This element is discussed in Section B.0.3 of the LRA, which indicates that IPEC administrative controls are in accordance with 10 CFR 50 Appendix B and consistent with NUREG-1801 (Volume 2 Appendix A, 2nd bullet).

Administrative controls in accordance with IWA-1400 include preparation of plans, schedules and summary reports, use of written examination instructions and procedures, qualification of personnel, and use of a quality assurance program. In accordance with 10 CFR 50.55a(g)(6)(ii)(B)(5), the program plan is not submitted to the NRC staff for approval. Rather, the program elements and the required documentation are maintained on site for audit.

Preparation, submittal, and retention of records and reports are in accordance with IWA-6000 or alternatives approved in 10 CFR 50.55a.

IPEC administrative controls are in accordance with 10 CFR 50 Appendix B.

IPEC administrative controls are consistent with NUREG-1801.

10. Operating Experience

NUREG-1801 Operating Experience

"ASME Section XI, Subsection IWL was incorporated into 10 CFR 50.55a in 1996. Prior to this time, operating experience pertaining to degradation of reinforced concrete and prestressing systems in concrete containments was gained through the inspections required by 10 CFR Part 50, Appendix J and ad hoc inspections conducted by licensees and the Nuclear Regulatory Commission (NRC). Recently, NRC Information Notice (IN) 99-10 described occurrences of degradation in prestressing systems. The program is to consider the degradation concerns described in this generic communication. Implementation of Subsection IWL, in accordance with 10 CFR 50.55a, is a necessary element of aging management for concrete containments through the period of extended operation."

Comparison to IPEC Operating Experience

For IP2 an IWL inspection in 2005 revealed 91 recordable indications which were reviewed by engineering. None of these indications, which were compared to the results of the 2000 inspection, represented a structural concern. For IP3 an IWL inspection in 2005 found minor spalling and other indications which had been noted in the 2001 inspection and which showed no signs of further degradation. There was no structural concern.

A self-assessment of the Containment ISI program was completed in October 2004. All findings and recommendations from earlier EPRI assessments of the program were found to be evaluated, and corrected.

IP2 and IP3 containments are reinforced concrete structures that do not utilize a prestressing system. Therefore, operating experience related to prestressing systems does not apply.

IPEC operating experience is consistent with NUREG-1801.

Audit Item 50

LRA Section A.2.1.15, Flux Thimble Tube Inspection Program, is revised as follows.

The Flux Thimble Tube Inspection Program is an existing program that monitors for thinning of the flux thimble tube wall, which provides a path for the incore neutron flux monitoring system detectors and forms part of the RCS pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. An NDE methodology, such as eddy current testing (ECT), ~~or other similar inspection method~~ is used to monitor for wear of the flux thimble tubes. This program implements the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors".

LRA Section A.3.1.15, Flux Thimble Tube Inspection Program, is revised as follows.

The Flux Thimble Tube Inspection Program is an existing program that monitors for thinning of the flux thimble tube wall, which provides a path for the incore neutron flux monitoring system detectors and forms part of the RCS pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. An NDE methodology, such as eddy current testing (ECT), ~~or other similar inspection method~~ is used to monitor for wear of the flux thimble tubes. This program implements the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors".

The program description in LRA Section B.1.16, Flux Thimble Tube Inspection Program, is revised as follows.

The Flux Thimble Tube Inspection Program is an existing program that monitors thinning of the flux thimble tube wall, which provides a path for the incore neutron flux monitoring system detectors and forms part of the RCS pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. An NDE methodology, such as eddy current testing (ECT), ~~or other similar inspection method~~ is used to monitor for wear of the flux thimble tubes. This program implements the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors."

Audit Item 52

LRA Section A.2.1.16, Heat Exchanger Monitoring Program, is revised as follows.

The Heat Exchanger Monitoring Program will be enhanced to include the following.

- Revise applicable procedures 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

LRA Section A.3.1.16, Heat Exchanger Monitoring Program, is revised as follows.

The Heat Exchanger Monitoring Program will be enhanced to include the following.

- Revise applicable procedures 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
  - ~~instrument air heat exchangers~~
  - spent fuel pit heat exchangers
  - secondary system steam generator sample coolers
  - waste gas compressor heat exchangers

LRA Section B.1.17, Heat Exchanger Monitoring Program, Scope of Program, is revised as follows.

The Heat Exchanger Monitoring Program manages loss of material on selected heat exchangers required for efficient and reliable power generation. Steam generators are not included in this program.

Enhancement: Enhance applicable procedures 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
- ~~instrument air heat exchangers (IP3 only)~~
- 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)

LRA Section B.1.17, Heat Exchanger Monitoring Program, Enhancements, is revised as follows.

The following enhancements to the Heat Exchanger Monitoring Program will be implemented prior to the period of extended operation.

Attributes Affected	Enhancements
1. Scope of Program	Revise applicable procedures 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 • ~~instrument air heat exchangers (IP3 only)~~ • 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)

Audit Item 58

LRA Section B.1.18, Inservice Inspection, Scope of Program, second paragraph, is revised as follows.

The ISI Program manages cracking for carbon steel, carbon steel with stainless steel cladding, and stainless steel components, including bolting. The ISI Program implements applicable requirements of ASME Section XI, Subsections IWA, IWB, IWC, IWD, IWF and other requirements specified in 10 CFR 50.55a with approved NRC alternatives. The ISI Program also manages reduction of fracture toughness for valve bodies and pump casing made of cast austenitic stainless steel. ~~Both IP2 and IP3 use ASME Code Case N-481 as approved in Regulatory Guide 1.147 for managing the effects of loss of fracture toughness due to thermal aging embrittlement of CASS pump casing pressure retaining welds. ASME Code Case N-481 has been incorporated in later editions of the code and IP2 will not reference Code Case N-481 in the 4th interval.~~

LRA Section B.1.37, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS), Program Description, second paragraph, is revised as follows.

For pump casings and valve bodies, based on the assessment documented in the letter dated May 19, 2000, from Christopher Grimes, Nuclear Regulatory Commission (NRC), to Douglas Walters, Nuclear Energy Institute (NEI), screening for susceptibility to thermal aging is not required. The existing ASME Section XI inspection requirements~~, including the alternative requirements of ASME Code Case N-481 for pump casings,~~ are adequate for all pump casings and valve bodies.

Audit Item 59

LRA Section A.2.1.17, Inservice Inspection (ISI) Program, fourth paragraph, is revised as follows.

The ISI Program will be enhanced to include the following.

- Revise appropriate procedures to provide periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump support systems.

LRA Section A.3.1.17, Inservice Inspection (ISI) Program, fourth paragraph, is revised as follows.

The ISI Program will be enhanced to include the following.

Revise appropriate procedures to provide periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump support systems.

LRA Section B.1.18, Inservice Inspection, Detection of Aging Effects, seventh paragraph, is revised as follows.

Enhancement: The ISI Program will be revised to provide periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump supports.

LRA Section B.1.18, Inservice Inspection, Enhancements, is revised as follows.

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

Attributes Affected	Enhancements
4. Detection of Aging Effects	Revise appropriate procedures to provide periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump support systems.

Audit Item 60

LRA Section B.1.18, Inservice Inspection, Detection of Aging Effects, eighth paragraph, is deleted as follows.

~~IP2 and IP3 have adopted risk-informed inservice inspection (RI-ISI) as an alternative to current ASME Section XI inspection requirements for Class 1, Category B-F and B-J welds pursuant to 10 CFR 50.55a(a)(3)(i). The RI-ISI was developed in accordance with the EPRI methodology contained in EPRI TR-112657, Rev. B-A, "Revised Risk-Informed Inservice Inspection Evaluation Procedure." The risk informed inspection locations are identified as Category R-A.~~

Audit Item 61

LRA Section B.1.18, Inservice Inspection, Monitoring and Trending, second paragraph, is revised as follows.

ISI results are recorded every operating cycle and provided to the NRC after each refueling outage via Owner's Activity Reports. These reports include scope of inspection and significant inspection results. ~~They are prepared and submitted in accordance with NRC-accepted ASME Section XI Code Case N-532-1 as approved by RG 1.147.~~

Audit Item 63

LRA Section B.1.22, Non-EQ Bolted Cable Connections, Detection of Aging Effects, is revised as follows.

A representative sample of electrical connections within the scope of license renewal, and subject to aging management review will be inspected or tested prior to the period of extended operation to verify there are no aging effects requiring management during the period of extended operation. The factors considered for sample selection will be application (medium and low voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selected will be documented. Inspection methods may include thermography, contact resistance testing, or other appropriate methods including visual based on plant configuration and industry guidance. <u>Visual inspection should be used instead of destructive examination when other methods cannot be used.</u> The one-time inspection provides additional confirmation to support industry operating experience that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective.

<u>Audit Item 64</u>

LRA Section B.1.24, Non-EQ Instrumentation Circuits Test Review, Program Description, is revised as follows.

> The Non-EQ Instrumentation Circuits Test Review Program is a new program that assures the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized equipment environments caused by heat, radiation and moisture; (i.e., neutron flux monitoring instrumentation <u>and high range radiation monitors</u>); can be maintained consistent with the current licensing basis through the period of extended operation. Most <u>sensitive instrumentation circuit</u> ~~neutron flux monitoring system~~ cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provides sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results will be performed once every ten years, with the first review occurring before the period of extended operation.
>
> For <u>sensitive instrumentation circuit</u> ~~neutron monitoring system~~ cables that are disconnected during instrument calibrations, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry) will occur at least every ten years, with the first test occurring before the period of extended operation. In accordance with the corrective action program, an engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented to ensure that he intended functions of the cables can be maintained consistent with the current licensing basis through the period of extended operation. This program will consider the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR 109619.

LRA Section A.2.1.23, Non-EQ Instrumentation Circuits Test Review, Program Description, is revised as follows.

> The Non-EQ Instrumentation Circuits Test Review Program is a new program that assures the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized equipment environments caused by heat, radiation and moisture; (i.e., neutron flux monitoring instrumentation <u>and high range radiation monitors</u>); can be maintained consistent with the current licensing basis through the period of extended operation. Most <u>sensitive instrumentation circuit</u> ~~neutron flux monitoring system~~ cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provides sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results will be performed once every ten years, with the first review occurring before the period of extended operation.
>
> For <u>sensitive instrumentation circuit</u> ~~neutron monitoring system~~ cables that are disconnected during instrument calibrations, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry) will occur at least every ten years, with the first test occurring before the period of extended operation. In accordance with the corrective action program, an engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented to ensure that the intended functions of the cables can be

maintained consistent with the current licensing basis through the period of extended operation. This program will consider the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96- 0344, and EPRI TR-109619.

LRA Section A.3.1.23, Non-EQ Instrumentation Circuits Test Review, Program Description, is revised as follows.

The Non-EQ Instrumentation Circuits Test Review Program is a new program that assures the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized equipment environments caused by heat, radiation and moisture; (i.e., neutron flux monitoring instrumentation and high range radiation monitors); can be maintained consistent with the current licensing basis through the period of extended operation. Most sensitive instrumentation circuit ~~neutron flux monitoring system~~ cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provides sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results will be performed once every ten years, with the first review occurring before the period of extended operation.

For sensitive instrumentation circuit ~~neutron monitoring system~~ cables that are disconnected during instrument calibrations, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry) will occur at least every ten years, with the first test occurring before the period of extended operation. In accordance with the corrective action program, an engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented to ensure that the intended functions of the cables can be maintained consistent with the current licensing basis for the period of extended operation. This program will consider the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR 109619.

Audit Item 65

LRA Section B.1.25, Non-EQ Insulated Cables And Connections, Program Description, second paragraph, is revised as follows.

A representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. The program sample consists of all accessible cables and connections in localized adverse environments. ~~The technical basis for sampling will be determined using EPRI document TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments."~~

LRA Section A.2.1.24, Non-EQ Insulated Cables And Connections, Program Description, second paragraph, is revised as follows.

A representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. The program sample consists of all accessible cables and connections in localized adverse environments. ~~The technical basis for sampling will be determined using EPRI document TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments."~~

LRA Section A.3.1.24, Non-EQ Insulated Cables And Connections, Program Description, second paragraph, is revised as follows.

A representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. The program sample consists of all accessible cables and connections in localized adverse environments. ~~The technical basis for sampling will be determined using EPRI document TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments."~~

Audit Item 86

LRA Section A.2.1.35, Structures Monitoring, second paragraph, second bullet, is revised as follows.

- Appropriate procedures will be revised to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable.
  - cable trays and supports
  - concrete portion of reactor vessel supports
  - conduits and supports
  - cranes, rails, and girders
  - equipment pads and foundations
  - fire proofing (pyrocrete)
  - HVAC duct supports
  - jib cranes
  - manholes and duct banks
  - manways, hatches, and hatch covers
  - monorails
  - new fuel storage racks
  - sumps, sump screens, strainers and flow barriers

LRA Section A.3.1.35, Structures Monitoring, second paragraph, second bullet, is revised as follows.

- Appropriate procedures will be revised to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable.

    - cable trays and supports
    - concrete portion of reactor vessel supports
    - conduits and supports
    - cranes, rails, and girders
    - equipment pads and foundations
    - fire proofing (pyrocrete)
    - HVAC duct supports
    - jib cranes
    - manholes and duct banks
    - manways, hatches, and hatch covers
    - monorails
    - new fuel storage racks
    - sumps, sump screens, strainers and flow barriers

LRA Section B.1.36, Structures Monitoring, Enhancements, is revised as follows.

Enhancements

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

Attributes Affected	Enhancements
1. Scope of Program	Appropriate procedures will be revised to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails, and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches, and hatch covers • monorails • new fuel storage racks • sumps, sump screens, strainers and flow barriers

Audit Item 87

LRA Section A.2.1.35, Structures Monitoring, second paragraph, fifth bullet, is revised as follows.

- Guidance 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) will be added to the Structures Monitoring Program. The site will obtain samples from at least five wells that ~~is~~ are representative of the groundwater surrounding below-grade site structures. Samples will be monitored for sulfates, pH and chlorides.

LRA Section A.3.1.35, Structures Monitoring, second paragraph, fifth bullet, is revised as follows.

- Guidance 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) will be added to the Structures Monitoring Program. The site will obtain samples from at least five wells that ~~is~~ are representative of the groundwater surrounding below-grade site structures. Samples will be monitored for sulfates, pH and chlorides.

LRA Section B.1.36, Structures Monitoring, Enhancements, is revised as follows.

Enhancements

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

Attributes Affected	Enhancements
4. Detection of Aging Effects	Guidance 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) will be added to the Structures Monitoring Program. IPEC will obtain samples from at least five wells that ~~is~~ are representative of the ground water surrounding below-grade site structures. Samples will be monitored for sulfates, pH and chlorides.

Audit Item 88

LRA Sections A.2.1.35 and A.3.1.35, Structures Monitoring, second paragraph, is revised to add the following bullet.

- Revise applicable structures monitoring procedures to inspect normally submerged concrete portions of the intake structures at least once every 5 years.

LRA Section B.1.36, Structures Monitoring, Enhancements, is revised as follows.

Enhancements

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

Attributes Affected	Enhancements
1. Scope of Program 4. Detection of Aging Effects	Guidance will be added to the Structures Monitoring Program to inspect inaccessible concrete areas that are exposed by excavation for any reason. IPEC 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 inspection of normally submerged concrete portions of the intake structures at least once every 5 years.

Audit Item 90

LRA Section 3.2.2.1.2, Containment Spray System, is revised as follows.

Aging Management Programs

The following aging management programs manage the aging effects for containment spray system components.

- Bolting Integrity
- Boric Acid Corrosion Prevention
- External Surfaces Monitoring
- Periodic Surveillance and Preventive Maintenance
- ~~Water Chemistry Control – Auxiliary Systems~~
- Water Chemistry Control – Primary and Secondary

LRA Table 3.2.2-2-IP3, Containment Spray System Summary of Aging Management Review, is revised as follows.

Flow element	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	~~Water Chemistry Control – Auxiliary Systems~~ Periodic Surveillance and Preventive Maintenance	--	--	G, 202
Flow element	Pressure boundary	Stainless steel	Treated water (int)	Cracking	~~Water Chemistry Control – Auxiliary Systems~~ Periodic Surveillance and Preventive Maintenance	--	--	G, 202
Piping	Pressure boundary	Stainless steel	Treated water (int)	Cracking	~~Water Chemistry Control – Auxiliary Systems~~ Periodic Surveillance and Preventive Maintenance	--	--	G, 202
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	~~Water Chemistry Control – Auxiliary Systems~~ Periodic Surveillance and Preventive Maintenance	--	--	G, 202
Tank	Pressure boundary	Carbon steel with stainless cladding	Treated water (int)	Cracking	~~Water Chemistry Control – Auxiliary Systems~~ Periodic Surveillance and Preventive Maintenance	--	--	G, 202
~~Tank~~	~~Pressure boundary~~	~~Carbon steel with stainless cladding~~	~~Treated water (int)~~	~~Loss of material~~	~~Water Chemistry Control – Auxiliary Systems~~	~~--~~	~~--~~	~~G, 202~~
Tank	Pressure boundary	Carbon steel with stainless cladding	Treated water (int)	Loss of material	Periodic Surveillance and Preventive Maintenance	--	--	G, 202
Tubing	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	~~Water Chemistry Control – Auxiliary Systems~~ Periodic Surveillance	--	--	G, 202

					and Preventive Maintenance			
Tubing	Pressure boundary	Stainless steel	Treated water (int)	Cracking	~~Water Chemistry Control – Auxiliary Systems~~ Periodic Surveillance and Preventive Maintenance	--	--	G, 202
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	~~Water Chemistry Control – Auxiliary Systems~~ Periodic Surveillance and Preventive Maintenance	--	--	G, 202
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Cracking	~~Water Chemistry Control – Auxiliary Systems~~ Periodic Surveillance and Preventive Maintenance	--	--	G, 202

The discussion for Table 3.3.1, Summary of Aging Management Programs for the Auxiliary System Evaluated in Chapter VII of NUREG-1801, Item 3.3.1-46, is revised as follows.

Consistent with NUREG-1801 for components of closed cooling systems including the component cooling water and emergency diesel generator cooling systems. The Water Chemistry Control – Closed Cooling Water Program manages cracking for stainless steel components. ~~For other systems with controlled water chemistry, including the house service boiler systems, the Water Chemistry Control Auxiliary Systems Program manages cracking for stainless steel components.~~ The One-Time Inspection Program for Water Chemistry will use inspections or non-destructive examinations of representative samples to verify that the ~~Water Chemistry Control Auxiliary Systems and~~ Water Chemistry Control – Closed Cooling Water Program~~s~~ has~~ve~~ been effective at managing aging effects.

The discussion for Table 3.3.1, Summary of Aging Management Programs for the Auxiliary System Evaluated in Chapter VII of NUREG-1801, Item 3.3.1-47, is revised as follows.

Consistent with NUREG-1801 for components of closed cooling systems such as the component cooling water and emergency diesel generator cooling systems. The Water Chemistry Control – Closed Cooling Water Program manages loss of material for steel components. ~~For other systems with controlled water chemistry, such as the security diesel, or the house service boiler and the components of interfacing systems, the Water Chemistry Control Auxiliary Systems Program manages loss of material for steel components.~~ The One-Time Inspection Program for Water Chemistry will use visual inspections or non-destructive examinations of representative samples to verify that the ~~Water Chemistry Control Auxiliary Systems and~~ Water Chemistry Control – Closed Cooling Water Programs~~s~~ has~~ve~~ been effective at managing aging effects.

The discussion for Table 3.3.1, Summary of Aging Management Programs for the Auxiliary System Evaluated in Chapter VII of NUREG-1801, Item 3.3.1-50, is revised as follows.

Consistent with NUREG-1801 for components of closed cooling systems such as the component cooling water and emergency diesel generator cooling systems. The Water Chemistry Control – Closed Cooling Water Program manages loss of material for stainless steel components. ~~For other systems with controlled water chemistry, such as the house service boiler systems, the Water Chemistry Control – Auxiliary Systems Program manages loss of material for stainless steel components.~~ The One-Time Inspection Program for Water Chemistry will use visual inspections or non-destructive examinations of representative samples to verify that the ~~Water Chemistry Control Auxiliary Systems and~~ Water Chemistry Control – Closed Cooling Water Programs~~s~~ has~~ve~~ been effective at managing aging effects.

The discussion for Table 3.3.1, Summary of Aging Management Programs for the Auxiliary System Evaluated in Chapter VII of NUREG-1801, Item 3.3.1-51, is revised as follows.

Consistent with NUREG-1801 for components of closed cooling systems such as the component cooling water and emergency diesel generator cooling systems. The Water Chemistry Control – Closed Cooling Water Program manages loss of material for copper alloy components. ~~For other systems with controlled water chemistry, such as the security diesel, or the house service boiler and the components of interfacing systems, the Water Chemistry Control – Auxiliary Systems Program manages loss of material for copper alloy components.~~ The One-Time Inspection Program for Water Chemistry will use visual inspections or non-destructive examinations of representative samples to verify that the ~~Water Chemistry Control Auxiliary Systems and~~ Water Chemistry Control – Closed Cooling Water Programs~~s~~ has~~ve~~ been effective at managing aging effects.

Plant specific notes for Tables 3.3.2-1-IP2 through 3.3.2-19-62-IP3 are revised as follows.

312. ~~This environment is steam produced from treated water that is controlled by the Water Chemistry Control – Auxiliary Systems Program. Although this environment does not directly compare with any NUREG-1801 defined environment, the steam is considered equivalent to the NUREG-1801 steam environment for this comparison.~~

LRA Table 3.3.2-19-16-IP2, House Service Boiler System, is revised as follows.

Filter housing	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-16 (S-06)	3.4.1-2	~~E, 312~~ C, 314
Filter housing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-14 (A-25)~~ VIII.B1-11 (S-10)	~~3.3.1-47~~ 3.4.1-4	~~E, 304~~ C, 314
Flow element	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-16 (S-06)	3.4.1-2	~~E, 312~~ C, 314
Flow element	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-14 (A-25)~~ VIII.B1-11 (S-10)	~~3.3.1-47~~ 3.4.1-4	~~E, 304~~ C, 314
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-14 (A-25)~~ VIII.B1-11 (S-10)	~~3.3.1-47~~ 3.4.1-4	~~E, 304~~ C, 314
Pump casing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-14 (A-25)~~ VIII.B1-11 (S-10)	~~3.3.1-47~~ 3.4.1-4	~~E, 304~~ C, 314
Sight glass	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-14 (A-25)~~ VIII.B1-11 (S-10)	~~3.3.1-47~~ 3.4.1-4	~~E, 304~~ C, 314
Steam trap	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-16 (S-06)	3.4.1-2	~~E, 312~~ C, 314
Strainer housing	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-16 (S-06)	3.4.1-2	~~E, 312~~ C, 314

Strainer housing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-14 (A-25)~~ VIII.B1-11 (S-10)	~~3.3.1-47~~ 3.4.1-4	~~E, 304~~ C, 314
Tank	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-14 (A-25)~~ VIII.B1-11 (S-10)	~~3.3.1-47~~ 3.4.1-4	~~E, 304~~ C, 314
Thermo well	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-16 (S-06)	3.4.1-2	~~E, 312~~ C, 314
Thermo well	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-14 (A-25)~~ VIII.B1-11 (S-10)	~~3.3.1-47~~ 3.4.1-4	~~E, 304~~ C, 314
Tubing	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-10 (SP-44)	3.4.1-39	~~E, 312~~ C
Tubing	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-12 (SP-43)	3.4.1-37	~~E, 312~~ C
Tubing	Pressure boundary	Stainless steel	Treated water > 140°F (int)	Cracking	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-11 (AP-60)~~ VIII.B1-5 (SP-17)	~~3.3.1-46~~ 3.4.1-14	~~E, 304~~ C, 314
Tubing	Pressure boundary	Stainless steel	Treated water > 140°F (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-10 (A-52)~~ VIII.B1-4 (SP-16)	~~3.3.1-50~~ 3.4.1-16	~~E, 304~~ C, 314
Turbine housing	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-16 (S-06)	3.4.1-2	~~E, 312~~ C, 314

Valve body	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-16 (S-06)	3.4.1-2	~~E, 312~~ C, 314
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-14 (A-25)~~ VIII.B1-11 (S-10)	~~3.3.1-47~~ 3.4.1-4	~~E, 304~~ C, 314
Valve body	Pressure boundary	Copper alloy > 15% Zn	Steam (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	--	--	G
Valve body	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-4 (AP-12)~~ VIII.A-5 (SP-61)	~~3.3.1-51~~ 3.4.1-15	~~E, 304~~ C, 314
Valve body	Pressure boundary	Gray cast iron	Steam (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-16 (S-06)	3.4.1-2	~~E, 312~~ C, 314
Valve body	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-14 (A-25)~~ VIII.B1-11 (S-10)	~~3.3.1-47~~ 3.4.1-4	~~E, 304~~ C, 314
Valve body	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-10 (SP-44)	3.4.1-39	~~E, 312~~ C
Valve body	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	VIII.A-12 (SP-43)	3.4.1-37	~~E, 312~~ C
Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (int)	Cracking	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-11 (AP-60)~~ VIII.B1-5 (SP-17)	~~3.3.1-46~~ 3.4.1-14	~~E, 304~~ C, 314

Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (int)	Loss of material	Water Chemistry Control – ~~Auxiliary Systems~~ Primary and Secondary	~~VII.C2-10 (A-52)~~ VIII.B1-4 (SP-16)	~~3.3.1-50~~ 3.4.1-16	~~E, 304~~ C, 314

LRA Section 3.4.2.2.2, Loss of Material Due to General, Pitting, and Crevice Corrosion, Item 1, second paragraph, is revised as follows.

~~This item is also compared to carbon steel components exposed to steam in the auxiliary systems. For steel auxiliary systems components exposed to steam from systems with controlled water chemistry such as the house service boiler system, the Water Chemistry Control – Auxiliary Systems Program manages loss of material. The One-Time Inspection Program for Water Chemistry will use visual inspections or non-destructive examinations of representative samples to verify that the Water Chemistry Control – Auxiliary Systems have been effective at managing aging effects.~~

The discussion for Table 3.4.1, Summary of Aging Management Programs for the Steam and Power Conversion System Evaluated in Chapter VIII of NUREG-1801, Item 3.4.1-2, is revised as follows.

Consistent with NUREG-1801 for steam and power conversion system components. Loss of material in steel components exposed to steam is managed by the Water Chemistry Control – Primary and Secondary Program. The One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program. ~~For some auxiliary systems components, loss of material is managed by the Water Chemistry Control – Auxiliary Systems Program. See Section 3.4.2.2.2 item 1.~~

The discussion for Table 3.4.1, Summary of Aging Management Programs for the Steam and Power Conversion System Evaluated in Chapter VIII of NUREG-1801, Item 3.4.1-37 is revised as follows.

Consistent with NUREG-1801 for steam and power conversion system components. The loss of material in steel and stainless steel components exposed to steam is managed by the Water Chemistry Control – Primary and Secondary Program. There are no nickel alloy components exposed to steam in the steam and power conversion systems. ~~For stainless steel components exposed to steam in systems with controlled water chemistry, such as the house service boiler system, the Water Chemistry Control – Auxiliary Systems Program manages loss of material.~~ The One-Time Inspection Program for Water Chemistry will use inspections or non-destructive examinations of representative samples to verify that the ~~Water Chemistry Control – Auxiliary Systems and~~ Water Chemistry Control – Primary and Secondary Program~~s~~ ha~~ve~~s been effective at managing aging effects.

The discussion for Table 3.4.1, Summary of Aging Management Programs for the Steam and Power Conversion System Evaluated in Chapter VIII of NUREG-1801, Item 3.4.1-39 is revised as follows.

Consistent with NUREG-1801 for steam and power conversion system components. Cracking of stainless steel components exposed to steam is managed by the Water Chemistry Control – Primary and Secondary Program. ~~For stainless steel components exposed to steam in systems with controlled water chemistry, such as the house service boiler system, the Water Chemistry Control – Auxiliary Systems Program manages cracking.~~ The One-Time Inspection Program for Water Chemistry will use inspections or non-destructive examinations of representative samples to verify that the ~~Water Chemistry Control – Auxiliary Systems and~~ Water Chemistry Control – Primary and Secondary Program~~s~~ has~~ve~~ been effective at managing aging effects.

Plant specific notes for Tables 3.4.2-1-IP2 through 3.4.2-4-IP3 are revised as follows.

~~403. This treated water environment is controlled by the Water Chemistry Control – Auxiliary Systems Program. Although this environment does not directly compare with any NUREG-1801 defined environment, it approximates the NUREG-1801 defined closed cycle cooling water environment.~~

LRA Section A.2.1.38, Water Chemistry Control – Auxiliary Systems, second paragraph, is revised as follows.

> Program activities include sampling and analysis to minimize component exposure to aggressive environments for ~~the house service boiler systems and~~ stator cooling water systems.

LRA Section A.3.1.38, Water Chemistry Control – Auxiliary Systems, second paragraph, is revised as follows.

> Program activities include sampling and analysis to minimize component exposure to aggressive environments for ~~NaOH components in the containment spray system, house service boiler systems, and~~ stator cooling water systems.

LRA Section B.1.39, Water Chemistry Control – Auxiliary Systems, Program Description, is revised as follows.

> The Water Chemistry Control – Auxiliary Systems Program is an existing program that manages loss of material and cracking for components exposed to treated water.
>
> Program activities include sampling and analysis to minimize component exposure to aggressive environments for ~~NaOH components in the containment spray system (IP3 only), house service boiler systems, and~~ stator cooling water systems.
>
> The One-Time Inspection Program for Water Chemistry utilizes inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – Auxiliary Systems Program has been effective at managing aging effects.

Evaluation

1. Scope of Program

Program activities include sampling and analysis of the ~~NaOH tank in the containment spray system (IP3 only),~~ stator cooling water system~~, and house service boiler systems~~ to minimize component exposure to aggressive environments.

3. Parameters Monitored or Inspected

Treated water in the following systems is monitored to mitigate degradation through control of impurities.

~~Bulk chemical shipments of NaOH are monitored for sodium chloride, sodium carbonate, iron, specific gravity, and visual clarity upon arrival. The NaOH tank is monitored for sodium hydroxide concentration every six months. Makeup water to the tank is addressed by the Water Chemistry Control - Primary and Secondary program. A nitrogen blanket is maintained continuously to remove oxygen.~~

Stator cooling water is monitored for copper and conductivity monthly.

~~The house service boilers are monitored for dissolved oxygen and pH at least weekly.~~

6. Acceptance Criteria

~~Acceptance criteria for the NaOH shipments are as follows.~~

~~**Parameter**~~	~~**Acceptance Criteria**~~
~~NaOH (% by weight)~~	~~49 to 51.5~~
~~Sodium Carbonate (% by weight)~~ ~~(ppm)~~	~~≤ 0.05~~ ~~≤ 762.5~~
~~Sodium Chloride (% by weight)~~ ~~(ppm)~~	~~≤ 0.01~~ ~~≤ 106.75~~
~~Iron (% by weight)~~ ~~(ppm)~~	~~≤ 0.005~~ ~~≤ 76.75~~
~~Specific gravity~~	~~1.49 to 1.585~~
~~Visual clarity~~	~~clear, free of suspended matter~~
~~NaOH concentration (%)~~	~~35 to 38~~

Acceptance criteria for the stator cooling water systems are as follows.

Parameter	**Acceptance Criteria**
Conductivity	< 0.5 μmhos/cm
Copper	< 20 ppb

~~Acceptance criteria for the house service boiler systems are as follows.~~

~~**Parameter**~~	~~**Acceptance Criteria**~~
~~pH~~	~~As specified for the specific chemistry treatment.~~
~~Dissolved oxygen~~	~~< 100 ppb~~

Audit Item 91

Refer to Audit Item 90.

Audit Item 95

LRA Section B.1.40, Water Chemistry Control – Closed Cooling Water System, Exceptions to NUREG-1801, is revised as follows.

Attributes Affected	Exception
5. Monitoring and Trending	NUREG-1801 recommends internal visual inspections and performance and functional tests periodically to demonstrate system operability. The IPEC Water Chemistry Control - Closed Cooling Water Program does not perform ~~visual inspections,~~ component performance~~,~~ and functional testing. [1]

Audit Item 105

LRA Table 3.0-1, Service Environments for Mechanical Aging Management Reviews, is revised to remove fire protection foam as follows.

Table 3.0-1
Service Environments for Mechanical Aging Management Reviews

Environment	Description
~~Fire protection foam~~	~~Fluoroprotein foam concentrate stored as a liquid for combination with water for fire suppression~~

LRA Section 3.3.2.1.19, Miscellaneous Systems in Scope for 10 CFR 54.4(a)(2), Environment, is revised as follows.

Nonsafety-related components affecting safety-related systems are exposed to the following environments.

- air – indoor
- air – treated
- condensation
- ~~fire protection foam~~
- fuel oil
- gas
- lube oil
- raw water
- steam
- treated borated water

- treated borated water > 140°F
- treated water
- treated water > 140°F

LRA Table 3.3.2-19-11-IP2, Fire Protection System Nonsafety-Related Components Potentially Affecting Safety Functions Summary of Aging Management Review, is revised as follows.

~~Tank~~	~~Pressure boundary~~	~~Carbon steel~~	~~Air – indoor (ext)~~	~~Loss of material~~	~~External Surfaces Monitoring~~	~~VII.I-8 (A-77)~~	~~3.3.1-58~~	~~A~~
~~Tank~~	~~Pressure boundary~~	~~Carbon steel~~	~~Fire protection foam (int)~~	~~Loss of material~~	~~Fire Water System~~	~~--~~	~~--~~	~~G~~

LRA Table 3.3.2-19-20-IP3, Fire Water System Nonsafety-Related Components Potentially Affecting Safety Functions Summary of Aging Management Review, is revised as follows.

~~Piping~~	~~Pressure boundary~~	~~Carbon steel~~	~~Fire protection foam (int)~~	~~Loss of material~~	~~Fire Water System~~	~~--~~	~~--~~	~~G~~
~~Tank~~	~~Pressure boundary~~	~~Carbon steel~~	~~Air – indoor (ext)~~	~~Loss of material~~	~~External Surfaces Monitoring~~	~~VII.I-8 (A-77)~~	~~3.3.1-58~~	~~A~~
~~Tank~~	~~Pressure boundary~~	~~Carbon steel~~	~~Fire protection foam (int)~~	~~Loss of material~~	~~Fire Water System~~	~~--~~	~~--~~	~~G~~
~~Valve body~~	~~Pressure boundary~~	~~Carbon steel~~	~~Fire protection foam (int)~~	~~Loss of material~~	~~Fire Water System~~	~~--~~	~~--~~	~~G~~

LRA Section B.1.14, Fire Water System, Enhancements, is revised as follows.

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

Attributes Affected	Enhancements
~~3. Parameters Monitored or Inspected~~ ~~4. Detection of Aging Effects~~ ~~6. Acceptance Criteria~~	~~IP3: Revise applicable procedures to inspect the internal surface of the foambased fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.~~

LRA Section A.3.1.13, Fire Water System Program, fourth paragraph, second bullet is revised as follows.

- ~~Revise applicable procedures to inspect the internal surface of the foam-based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.~~

Audit Item 106

LRA Section B.1.14, Fire Water System, Enhancements, is revised as follows.

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

Attributes Affected	Enhancements
4. Detection of Aging Effects	~~A sample of~~ Sprinkler heads required for 10 CFR 50.48 will be ~~inspected~~ replaced or a sample tested 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.

LRA Section A.2.1.13, Fire Water System Program, fourth paragraph, second bullet is revised as follows.

- ~~A sample of~~ Sprinkler heads required for 10 CFR 50.48 will be ~~inspected~~ replaced or a sample tested 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.

LRA Section A.3.1.13, Fire Water System Program, fourth paragraph, third bullet is revised as follows.

- ~~A sample of~~ Sprinkler heads required for 10 CFR 50.48 will be ~~inspected~~ replaced or a sample tested 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.

Audit Item 124

LRA Section B.1.20, Metal Enclosed Bus Inspection, Program Description, second paragraph is replaced with the following.

Inspections of the metal enclosed bus (MEB) include the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. A sample of the accessible bolted connections will be inspected for loose connections. The bus enclosure assemblies will be inspected for loss of material and elastomer degradation. This program will be used instead of the Structures Monitoring Program for external surfaces of the bus enclosure assemblies. The internal portions of the MEB will be inspected for foreign debris, excessive dust buildup, and evidence of moisture intrusion. The bus insulation or insulators are inspected for degradation leading to reduced insulation resistance (IR). The bus insulation will be inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The internal bus supports or insulators will be inspected for structural integrity and signs of cracks and corrosion. These inspections include visual inspections, as well as quantitative measurements, such as thermography or connection resistance measurements, as required.

LRA Section B.1.20, Metal Enclosed Bus Inspection, Enhancements, is revised as follows.

Attributes Affected	Enhancements
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Revise appropriate procedures 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.
4. Detection of Aging Effects	Revise appropriate procedures to inspect bolted connections ~~visually~~ at least once every five years if only 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.

LRA Section A.2.1.19, Metal Enclosed Bus Inspection Program, second paragraph, is replaced with the following.

Inspections of the metal enclosed bus (MEB) include the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. A sample of the accessible bolted connections will be inspected for loose connections. The bus enclosure assemblies will be inspected for loss of material and elastomer degradation. This program will be used instead of the Structures Monitoring Program for external surfaces of the bus enclosure assemblies. The internal portions of the MEB will be inspected for foreign debris, excessive dust buildup, and evidence of moisture intrusion. The bus insulation or insulators are inspected for degradation leading to reduced insulation resistance (IR). The bus insulation will be inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The internal bus supports or insulators will be inspected for structural integrity and signs of cracks and corrosion. These inspections include visual inspections, as well as quantitative measurements, such as thermography or connection resistance measurements, as required.

LRA Section A.3.1.19, Metal Enclosed Bus Inspection Program, second paragraph, is replaced with the following.

Inspections of the metal enclosed bus (MEB) include the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. A sample of the accessible bolted connections will be inspected for loose connections. The bus enclosure assemblies will be inspected for loss of material and elastomer degradation. This program will be used instead of the Structures Monitoring Program for external surfaces of the bus enclosure assemblies. The internal portions of the MEB will be inspected for foreign debris, excessive dust buildup, and evidence of moisture intrusion. The bus insulation or insulators are inspected for degradation leading to reduced insulation resistance (IR). The bus insulation will be inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The internal bus supports or insulators will be inspected for structural integrity and signs of cracks and corrosion. These inspections include visual inspections, as well as quantitative measurements, such as thermography or connection resistance measurements, as required.

LRA Section A.2.1.19, Metal Enclosed Bus Inspection Program, third paragraph, third bullet is revised as follows.

- Revise appropriate procedures to inspect bolted connections ~~visually~~ at least once every five years if only performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements.

LRA Section A.3.1.19, Metal Enclosed Bus Inspection Program, third paragraph, second bullet is revised as follows.

- Revise appropriate procedures to inspect bolted connections ~~visually~~ at least once every five years if only performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements.

Audit Item 128

LRA Section B.1.9, Diesel Fuel Monitoring, Enhancements, is revised as follows.

Enhancements

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

Attributes Affected	Enhancements
2. Preventive Actions	Revise applicable procedures to direct samples be taken near the tank bottom and include direction to remove water when detected.

LRA Section A.2.1.8, Diesel Fuel Monitoring Program, is revised to add the following enhancement.

- Revise applicable procedures to direct samples taken near the tank bottom and include direction to remove water when detected.

LRA Section A.3.1.8, Diesel Fuel Monitoring Program, is revised to add the following enhancement.

- Revise applicable procedures to direct samples taken near the tank bottom and include direction to remove water when detected.

Audit Item 129

See Audit Item 128 LRA revision.

Audit Item 131

LRA Section B.1.9, Diesel Fuel Monitoring, Exception and Exception Note 4 are revised as follows.

Attributes Affected	Exception
6. Acceptance Criteria	NUREG-1801 recommends the use of ASTM Standards D1796 and D2709. Only ASTM Standard D1796 is used for testing water and sediment. [2] For determination of particulates, NUREG-1801 recommends the use of modified ASTM Standard D2276 Method A and D6217. Determination of particulates is according to ASTM Standard D2276. [4]

Exception Notes:

[4] Determination of particulates is according to ASTM Standard D2276 which conducts particulate analysis

using a 0.8 micron filter, rather than the 3.0 micron filter specified in NUREG-1801. Use of a filter with a smaller pore size results in a larger sample of particulates since smaller particles are retained. Thus, use of a 0.8 micron filter is more conservative than use of the 3.0 micron filter specified in NUREG-1801. ASTM D6217 applies to middle distillate fuel using a smaller volume of sample passing over the 0.8 micron filter. Since ASTM D2276 determines particulates with a larger volume passing through the filter for a longer time than the D6217 method, use of D2276 only is more conservative.

Audit Item 132

LRA Section B.1.9, Diesel Fuel Monitoring, Enhancements is revised as follows.

Enhancements

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

Attributes Affected	Enhancements
2. Preventive Actions	Revise applicable procedures to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.

LRA Section A.2.1.8, Diesel Fuel Monitoring Program, is revised to add the following enhancement.

- Revise applicable procedures to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.

LRA Section A.3.1.8, Diesel Fuel Monitoring Program, is revised to add the following enhancement.

- Revise applicable procedures to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.

Audit Item 156

LRA Section B.1.15, Flow-Accelerated Corrosion, is revised as follows.

Exceptions to NUREG-1801

The Flow-Accelerated Corrosion Program is consistent with the program described in NUREG-1801, Section XI., M17, Flow-Accelerated Corrosion Aging Management Program, with the following exceptions. ~~None~~

Attributes Affected	Exception
1. Scope of Program	IPEC utilizes EPRI NSAC-202L-R3, while NUREG-1801, Section XI., M17 references EPRI NSAC-202L-R2. [1]
4. Detection of Aging Effects	IPEC utilizes EPRI NSAC-202L-R3, while NUREG-1801, Section XI., M17 references EPRI NSAC-202L-R2. [2]

[1] The differences of Section 4.2, Identifying Susceptible Systems, between Revision 2 and Revision 3 include the following. The guidance of prioritizing the system for evaluation in Section 4.2.3 of Revision 2 is addressed in Section 4.9 of Revision 3. Section 4.4, Selecting and Scheduling Components for Inspection, of Revision 2 was re-organized in Revision 3. Sample selection for modeled lines and non-modeled lines of Revision 2 was enhanced with more clarification and more details in Revision 3. Guidance for using plant experience and industry experience in selecting inspection locations was added in Revision 3. The basis for sample expansion was clarified in Revision 3. Instead of dividing into selection of initial inspection and follow-up inspections in Revision 2, the guidance in Revision 3 is provided for a given outage including the recommendations for locations of re-inspection.

[2] Clarification of the inspection techniques of UT and RT was added in Section 4.5.1 of Revision 3. There are no changes of the guidance for UT grid. Appendix B was added in Revision 3 to provide guidance for inspection of vessels and tanks. This is beyond the level of detail provided in Revision 2 and in the GALL report. The guidance for inspection of small-bore piping in Appendix A of Revision 2 and of Revision 3 are essentially identical. The guidance for inspection of valves, orifices, and equipment nozzles was enhanced in Section 4.5.2 of Revision 3. Also, Section 4.5.4 was added for use of RT to inspect large-bore piping, Section 4.5.5 was added for inspection of turbine cross-around piping, and Section 4.5.6 was added for inspection of valves.

LRA Sections A.2.1.14, A.3.1.14, and B.1.15, Flow-Accelerated Corrosion, Program Description, second paragraph is revised as follows.

The program, based on EPRI guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R~~2~~3 for an effective flow-accelerated corrosion program, predicts, detects, and monitors FAC in plant piping and other pressure-retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions, or repair or replace components as necessary.

LRA Table B-3, IPEC Program Consistency with NUREG-1801, is revised to change the Flow-Accelerated Corrosion Program from "Programs Consistent with NUREG-1801" to "Programs with Exceptions to NUREG-1801".

Line items in LRA Section 3 crediting the Flow-Accelerated Corrosion Program with note 'A' are revised to use Note 'B'.

Line items in LRA Section 3 crediting the Flow-Accelerated Corrosion Program with note 'C' are revised to use Note 'D'.

Audit Item 165

LRA Section B.1.26, Oil Analysis, Program Description, second paragraph is replaced with the following.

> Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. Procedure EN-DC-335, "PM Bases Template", is based on EPRI PM bases documents TR-106857 volumes 1 thru 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure.

LRA Section A.2.1.25, Oil Analysis Program, second paragraph is replaced with the following.

> Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. Procedure EN-DC-335, "PM Bases Template", is based on EPRI PM bases documents TR-106857 volumes 1 thru 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure.

LRA Section A.3.1.25, Oil Analysis Program, second paragraph is replaced with the following.

> Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. Procedure EN-DC-335, "PM Bases Template", is based on EPRI PM bases documents TR-106857 volumes 1 thru 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure.

Audit Item 166

LRA Section B.1.26, Oil Analysis, Program Description, first paragraph is revised as follows.

> The Oil Analysis Program is an existing program that maintains oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951 and ASTM D96. Water, particle concentration and viscosity acceptance criteria are based on industry standards supplemented by manufacturers' recommendations ~~for detrimental contaminants, water, and particulates~~.

LRA Section A.2.1.25, Oil Analysis Program, first paragraph is revised as follows.

> The Oil Analysis Program is an existing program that maintains oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951 and ASTM D96. Water, particle concentration and viscosity acceptance criteria are based on industry standards supplemented by manufacturer's recommendations ~~for detrimental contaminants, water, and particulates~~.

LRA Section A.3.1.25, Oil Analysis Program, first paragraph is revised as follows.

> The Oil Analysis Program is an existing program that maintains oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951 and ASTM D96. Water, particle concentration and viscosity acceptance criteria are based on industry standards supplemented by manufacturer's recommendations ~~for detrimental contaminants, water, and particulates~~.

Audit Item 170

See Audit Item 165 LRA revision.

Audit Item 171

LRA Section A.2.1.26, One-Time Inspection Program, is revised as follows.

> The One-Time Inspection Program is a new program that includes measures to verify effectiveness of an aging management program (AMP) and confirm the absence of an aging effect. For structures and components that rely on an AMP, this program will verify effectiveness of the AMP by confirming that unacceptable degradation is not occurring and the intended function of a component will be maintained during the period of extended operation. One-time inspections may be needed to address concerns for potentially long incubation periods for certain aging effects on structures and components. There are cases where either (a) an aging

effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. For these cases, there will be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly as not to affect the component or structure intended function. A one-time inspection of the subject component or structure is appropriate for this verification. <u>The inspections will be nondestructive examinations (including visual, ultrasonic, or surface techniques).</u>

LRA Section A.3.1.26, One-Time Inspection Program, is revised as follows.

The One-Time Inspection Program is a new program that includes measures to verify effectiveness of an aging management program (AMP) and confirm the absence of an aging effect. For structures and components that rely on an AMP, this program will verify effectiveness of the AMP by confirming that unacceptable degradation is not occurring and the intended function of a component will be maintained during the period of extended operation. One-time inspections may be needed to address concerns for potentially long incubation periods for certain aging effects on structures and components. There are cases where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. For these cases, there will be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly as not to affect the component or structure intended function. A one-time inspection of the subject component or structure is appropriate for this verification. <u>The inspections will be nondestructive examinations (including visual, ultrasonic, or surface techniques).</u>

The program description, first paragraph, in LRA Section B.1.27, One-Time Inspection, is revised as follows.

The One-Time Inspection Program is a new program that includes measures to verify effectiveness of an aging management program (AMP) and confirm the absence of an aging effect. For structures and components that rely on an AMP, this program will verify effectiveness of the AMP by confirming that unacceptable degradation is not occurring and the intended function of a component will be maintained during the period of extended operation. One-time inspections may be needed to address concerns for potentially long incubation periods for certain aging effects on structures and components. There are cases where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. For these cases, there will be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly as not to affect the component or structure intended function. A one-time inspection of the subject component or structure is appropriate for this verification. <u>The inspections will be nondestructive examinations (including visual, ultrasonic, or surface techniques).</u>

<u>Audit Item 172</u>

LRA Section A.2.1.26, One-Time Inspection Program, sixth paragraph, is revised as follows.

One-time inspection activities on the following confirm that loss of material is not occurring or is so insignificant that an aging management program is not warranted.

- internal surfaces of stainless steel drain piping, piping elements and components containing raw water (drain water)
- internal surfaces of stainless steel piping, piping elements and components in the station air containment penetration exposed to condensation
- internal surfaces of stainless steel EDG starting air tanks, piping, piping elements and components exposed to condensation
- internal surfaces of carbon steel and stainless steel tanks, piping, piping elements and components in the RCP oil collection system exposed to lube oil
- internal surfaces of auxiliary feedwater system stainless steel piping, piping elements and components exposed to treated water from the city water system
- internal surfaces of stainless steel piping, piping elements and components in the containment penetration for gas analyzers exposed to condensation
- internal surfaces of circulating water stainless steel and CASS piping, piping elements and components containing raw water
- internal surfaces of intake structure system stainless steel piping, piping elements and components containing raw water
- internal surfaces of chemical feed system stainless steel tanks, pump casings, piping, piping elements and components containing treated water
- internal surfaces of city water system stainless steel and CASS piping, piping elements, and components containing treated water (city water)
- internal surfaces of EDG system stainless steel piping, piping elements and components containing condensation or treated water (city water)
- internal surfaces of fresh water cooling system stainless steel piping, piping elements and components containing treated water (city water)
- internal surfaces of integrated liquid waste handling system stainless steel tanks, pump casings, piping, piping elements and components containing raw water
- internal surfaces of lube oil system aluminum tanks, piping, piping elements and components containing raw water
- internal surfaces of river water service system stainless steel piping, piping elements and components containing raw water
- internal surfaces of waste disposal system stainless steel and CASS tanks, pump casings, piping, piping elements and components containing raw water
- internal surfaces of water treatment plant system stainless steel piping, piping elements and components containing treated water (city water)

LRA Section A.3.1.26, One-Time Inspection Program, sixth paragraph, is revised as follows.

One-time inspection activities on the following confirm that loss of material is not occurring or is so insignificant that an aging management program is not warranted.

- internal surfaces of stainless steel drain piping, piping elements and components containing raw water (drain water)
- internal surfaces of stainless steel piping, piping elements and components in the station air containment penetration exposed to condensation
- internal surfaces of stainless steel EDG starting air tanks, piping, piping elements and components exposed to condensation

- internal surfaces of carbon steel and stainless steel tanks, piping, piping elements and components in the RCP oil collection system exposed to lube oil
- internal surfaces of auxiliary feedwater system stainless steel piping, piping elements and components exposed to treated water from the city water system
- internal surfaces of stainless steel piping, piping elements and components in the containment penetration for gas analyzers exposed to condensation
- internal surfaces of circulating water stainless steel and CASS piping, piping elements and components containing raw water
- internal surfaces of ammonia/morpholine addition system stainless steel piping, piping elements and components containing treated water
- internal surfaces of boron and layup chemical addition system stainless steel tanks, pump casings, piping, piping elements and components containing treated water
- internal surfaces of city water makeup system stainless steel and CASS piping, piping elements and components containing treated water (city water)
- internal surfaces of gaseous waste disposal system CASS piping, piping elements and components containing condensation
- internal surfaces of hydrazine addition system stainless steel tanks, pump casings, piping, piping elements and components containing treated water
- Internal surfaces of liquid waste disposal system stainless steel and CASS tanks, pump casings, piping, piping elements and components containing raw water or treated water (city water)
- internal surfaces of nuclear equipment drain system stainless steel tanks, piping, piping elements and components containing raw water

The program description, sixth paragraph, in LRA Section B.1.27, One-Time Inspection, is revised as follows.

One-time inspection activities on the following confirm that loss of material is not occurring or is so insignificant that an aging management program is not warranted.

- Internal surfaces of drain system stainless steel piping, tubing, and valve bodies exposed to raw water (drain water) in EDG buildings, primary auxiliary buildings, and electrical tunnels. Also included are drains in the IP3 auxiliary feed pump building

- Internal surfaces of stainless steel valve bodies in the station air containment penetration exposed to condensation

- Internal surfaces of stainless steel piping, strainers, strainer housings, tanks, tubing and valve bodies exposed to condensation in the emergency diesel generator (EDG) starting air subsystem

- Internal surfaces of the carbon steel tanks, piping and valve bodies and stainless steel drain pans and flex hoses in the RCP oil collection system

- Internal surfaces of auxiliary feedwater system stainless steel tubing and valve bodies exposed to treated water (city water)

- Internal surfaces of stainless steel piping and valve bodies in the containment penetration for gas analyzers exposed to condensation
- Internal surfaces of circulating water (CW) system stainless steel or CASS piping, piping elements and components containing raw water

IP2

- Internal surfaces of intake structure (DOCK) system stainless steel piping, piping elements and components containing raw water
- Internal surfaces of chemical feed (CF) system stainless steel tanks, pump casings, piping, piping elements and components containing treated water
- Internal surfaces of city water (CYW) system stainless steel and CASS piping, piping elements and components containing treated water (city water)
- Internal surfaces of emergency diesel generator (EDG) system stainless steel piping, piping elements and components containing condensation or treated water (city water)
- Internal surfaces of fresh water cooling (FWC) system stainless steel piping, piping elements and components containing treated water (city water)
- Internal surfaces of integrated liquid waste handling (ILWH) system stainless steel tanks, pump casings, piping, piping elements and components containing raw water
- Internal surfaces of the lube oil (LO) system aluminum tanks, piping, piping elements and components containing raw water
- Internal surfaces of the river water service system (RW) stainless steel piping, piping elements and components containing raw water
- Internal surfaces of the waste disposal (WDS) system stainless steel and CASS tanks, pump casings, piping, piping elements and components containing raw water
- Internal surfaces of the water treatment plant (WTP) system stainless steel piping, piping elements and components containing treated water (city water)

IP3

- Internal surfaces of the ammonia/morpholine addition (AMA) system stainless steel piping, piping elements and components containing treated water
- Internal surfaces of the boron and layup chemical addition (BLCA) system stainless steel tanks, pump casings, piping, piping elements and components containing treated water
- Internal surfaces of city water makeup (CWM) system stainless steel and CASS piping, piping elements and components containing treated water (city water)

- Internal surfaces of the gaseous waste disposal (GWD) system CASS <u>tanks, pump casings, piping, piping elements and</u> components containing condensation
- Internal surfaces of the hydrazine addition (HA) system stainless steel <u>tanks, pump casings, piping, piping elements and</u> components containing treated water
- Internal surfaces of the liquid waste disposal (LWD) system stainless steel and CASS <u>tanks, pump casings, piping, piping elements and</u> components containing raw water or treated water (city water)
- Internal surfaces of the nuclear equipment drain (NED) system stainless steel <u>tanks, piping, piping elements and</u> components containing raw water.

<u>Audit Item 173</u>

LRA Sections A.2.1.5 and A.3.1.5, Buried Piping and Tanks Inspection Program, third paragraph, are revised as follows.

The Buried Piping and Tanks Inspection Program will be implemented prior to the period of extended operation. <u>This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection</u>.

LRA Sections A.2.1.22 and A.3.1.22, Non-EQ Inaccessible Medium-Voltage Cable Program, second paragraph, are revised as follows.

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

LRA Sections A.2.1.23 and A.3.1.23, Non-EQ Instrumentation Circuits Test Review Program, third paragraph, are revised as follows.

The Non-EQ Instrumentation Circuits Test Review Program will be implemented prior to the period of extended operation. <u>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.</u>

LRA Sections A.2.1.24 and A.3.1.24, Non-EQ Insulated Cables and Connections Program, third paragraph, are revised as follows.

The Non-EQ Insulated Cables and Connections Program will be implemented prior to the period of extended operation. <u>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.</u>

LRA Sections A.2.1.26 and A.3.1.26, One-Time Inspection Program, last paragraph, are revised as follows.

The inspection will be performed prior to the period of extended operation. <u>This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.</u>

LRA Sections A.2.1.27 and A.3.1.27, One-Time Inspection – Small Bore Piping Program, third paragraph, are revised as follows.

The inspection will be performed prior to the period of extended operation. <u>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.</u>

LRA Sections A.2.1.32 and A.3.1.32, Selective Leaching Program, second paragraph, are revised as follows.

The Selective Leaching Program will be implemented prior to the period of extended operation. <u>This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.</u>

LRA Sections A.2.1.36 and A.3.1.36, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program, second paragraph, are revised as follows.

The Thermal Aging Embrittlement of CASS Program will be implemented prior to the period of extended operation. <u>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.</u>

LRA Sections A.2.1.37 and A.3.1.37, Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program, second paragraph, are revised as follows.

The Thermal Aging and Neutron Irradiation Embrittlement of CASS Program will be implemented prior to the period of extended operation. <u>This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M13, Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.</u>

<u>Audit Item 175</u>

LRA Section A.2.1.25, Oil Analysis Program, fourth paragraph, is revised as follows.

The Oil Analysis Program will be enhanced to include the following.

- Revise appropriate procedures to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with oil analysis for other site diesel generators.

- Revise appropriate procedures to sample and analyze generator seal oil and turbine hydraulic control oil (electrohydraulic fluid).

- ~~Revise appropriate procedures to f~~ Formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the program. The ~~controlled documents~~ program will specify corrective actions in the event acceptance criteria are not met.

- ~~Revise appropriate procedures to f~~ Formalize trending of preliminary oil screening results as well as data provided from independent laboratories.

LRA Section A.3.1.25, Oil Analysis Program, fourth paragraph, is revised as follows.

The Oil Analysis Program will be enhanced to include the following.

- Revise appropriate procedures to sample and analyze generator seal oil and turbine hydraulic control oil (electrohydraulic fluid).

- ~~Revise appropriate procedures to f~~ Formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the program. The ~~controlled documents~~ program will specify corrective actions in the event acceptance criteria are not met.

- ~~Revise appropriate procedures to f~~ Formalize trending of preliminary oil screening results as well as data provided from independent laboratories.

Section B.1.26, Oil Analysis, Enhancements, is revised as follows.

Enhancements

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

Attributes Affected	Enhancements
2. Preventive Actions 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria 7. Corrective Actions	~~Revise appropriate procedures to f~~ Formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the program. The ~~controlled documents~~ program will specify corrective actions in the event acceptance criteria are not met.
5. Monitoring and Trending	~~Revise appropriate procedures to f~~ Formalize trending of preliminary oil screening results as well as data provided from independent laboratories.

Audit Item 176

LRA Section B.1.29, Periodic Surveillance and Preventive Maintenance, Program Description, is revised as follows.

The Periodic Surveillance and Preventive Maintenance Program is an existing program that includes periodic inspections and tests that manage aging effects not managed by other aging management programs. In addition to specific activities in the plant's preventive maintenance program and surveillance program, the Periodic Surveillance and Preventive Maintenance Program includes enhancements to add new activities. The preventive maintenance and surveillance testing activities are generally implemented through repetitive tasks or routine monitoring of plant operations. Credit for program activities has been taken in the aging management review of the following systems and structures. All activities are new unless otherwise noted.

Reactor building	Use visual or other NDE techniques to inspect the surface condition of carbon steel components of the reactor building cranes (polar and manipulator), crane rails, and girders, and refueling platform to manage loss of material. [existing]

Containment spray system	IP3: Perform wall thickness measurements of the NaOH tank to manage loss of material. [existing]
Safety injection system	Perform operability testing to manage fouling for recirculation pump motor cooling coils. Use visual or other NDE techniques to internally inspect the recirculation pump cooler housing to manage loss of material.
City water system	Use visual or other NDE techniques to inspect a representative sample of the internals of city water piping, piping elements, and components exposed to treated water (city water) to manage loss of material.
Chemical and volume control system	During quarterly surveillances perform visual inspection of the external surface of charging pump casings to manage cracking. [existing]
Plant drains	Use visual or other NDE techniques to inspect a representative sample of the internals of carbon steel plant drain piping, piping elements, and components to manage loss of material. IP2: Use visual or other NDE techniques to inspect the internals of backwater valves to manage loss of material. [existing]
Station air system	Use visual or other NDE techniques to internally inspect a representative sample of carbon steel station air containment penetration piping to manage loss of material.
Heating, ventilation, and air conditioning (HVAC) systems	Visually inspect and manually flex a representative sample of the HVAC duct flexible connections to manage cracking and change in material properties. Visually inspect the internals of portable blowers stored for emergency ventilation use. Visually inspect the internals of flexible trunks stored for emergency ventilation use.

Emergency diesel generators	Use visual or other NDE techniques to internally inspect a representative sample of EDG exhaust gas piping, piping elements, and components to manage loss of material. Visually inspect both inside and outside surfaces of elastomer duct flexible connections on the intake portion of EDG duct. Use visual or other NDE techniques to internally inspect a representative sample of EDG air intake and aftercooler piping, piping elements, and components to manage fouling and loss of material. Use visual or other NDE techniques to internally inspect a representative sample of EDG starting air piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect EDG cooling water makeup supply valves to manage loss of material.
Security generator system	Use visual or other NDE techniques to inspect a representative sample of security generator exhaust piping, piping elements, and components to manage loss of material on internal surfaces. Use visual or other NDE techniques to inspect the surface condition of the radiator tubes and fins to manage loss of material on external surfaces. [existing]
IP2 SBO/Appendix R Diesel Generator	Use visual or other NDE techniques to inspect internal surfaces of a representative sample of diesel exhaust gas piping, piping elements, and components to manage cracking and loss of material on internal surfaces. Use visual or other NDE techniques to inspect the internal surface condition of the engine turbocharger and aftercooler housing including external surfaces of tubes and fins to manage loss of material and fouling. Use visual or other NDE techniques to inspect the internal surfaces of the jacket water heat exchanger carbon steel bonnet and stainless steel tubes exposed to treated water (city water).

Fuel oil system	IP2: Use visual or other NDE techniques to internally inspect the fuel oil cooler for the SBO/Appendix R diesel generator to manage fouling. Use visual or other NDE techniques to inspect internal and external surfaces of the emergency fuel oil trailer transfer tank and associated valves for loss of material.
IP3 Appendix R Diesel Generator	Use visual or other NDE techniques to inspect a representative sample of diesel exhaust piping, piping elements, and components to manage cracking and loss of material on internal surfaces. [existing] Visually inspect the radiator internals to manage fouling. [existing] Use visual or other NDE techniques to internally inspect the aftercooler to manage fouling and loss of material. [existing] Use visual or other NDE techniques to internally inspect a representative sample of starting air piping, piping elements, and components to manage loss of material. [existing] Use visual or other NDE techniques to internally inspect a representative sample of crankcase exhaust subsystem piping, piping elements, and components to manage loss of material. [existing]
Auxiliary Feedwater	Use visual or other NDE techniques to internally inspect a representative sample of copper alloy and carbon steel piping, piping elements, and components to manage loss of material.
Containment Cooling and Filtration	Visually inspect both internally and externally and manually flex a representative sample of duct flexible connections to manage cracking and change in material properties. Inspect components inside the each fan cooling unit including damper housings, filter housings, moisture separators, and heat exchanger headers, housings, and tubes for loss of material.

Control Room HVAC	Visually inspect the internals of a representative sample of control room HVAC air cooled condensers and evaporators to manage loss of material and fouling. Visually inspect the internals of a representative sample of control room HVAC ducts and drip pans to manage loss of material. Visually inspect both internally and externally and manually flex a representative sample of duct flexible connections to manage cracking and change in material properties.
Nonsafety-related systems affecting IP2 safety-related systems	Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of circulating water system carbon steel and copper alloy piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect inside and outside surfaces of a representative sample of circulating water system elastomer flexible piping connections to manage loss of material and cracking and change in material properties. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of city water gray cast iron, carbon steel, and copper alloy piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of intake structure system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of emergency diesel generator carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of fresh water cooling copper alloy and carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of instrument air system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of integrated liquid waste handling system carbon steel piping, piping elements,

	and components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of lube oil system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of miscellaneous system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect the inside surface of the pressurizer relief tank to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of radiation monitoring system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of river water service system carbon steel and gray cast iron piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of station air system carbon steel and copper alloy piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of waste disposal system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of water treatment plant carbon steel and gray cast iron components to manage loss of material.

Nonsafety-related systems affecting IP3 safety-related systems	Use visual or other NDE techniques to internally inspect a representative sample of chlorination system gray cast iron piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of circulating water system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect inside and outside surfaces of a representative sample of circulating water system elastomer components to manage loss of material and cracking and change in material properties. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of city water makeup carbon steel, gray cast iron, and copper alloy piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of emergency diesel generator system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of floor drain system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of gaseous waste disposal system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of instrument air system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of liquid waste disposal system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of nuclear equipment drain system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect the inside surface of the pressurizer relief tank to manage loss of

	material. Use visual or other NDE techniques to internally inspect a representative sample of river water system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of station air system carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of steam generator sampling carbon steel piping, piping elements, and components to manage loss of material. Use visual or other NDE techniques to internally inspect a representative sample of secondary plant sampling system carbon steel piping, piping elements, and components to manage loss of material.

Audit Item 190

LRA Table 3.1.2-3-IP2 is revised as follows.

Heat exchanger (tubes)	Heat transfer	Stainless steel	Treated borated water > 140ûF (ext)	Fouling	Water Chemistry Control – Primary and Secondary			H, 104

LRA Table 3.1.2-3-IP3 is revised as follows.

Heat exchanger (tubes)	Heat transfer	Stainless steel	Treated borated water > 140ûF (ext)	Fouling	Water Chemistry Control – Primary and Secondary			H, 104

LRA Table 3.1.2-4-IP2 is revised as follows.

Tube	Heat transfer	Nickel alloy	Treated borated water (int)	Fouling	Water Chemistry Control – Primary and Secondary	--	--	H, 104
			Treated water (ext)	Fouling	Water Chemistry Control – Primary and Secondary	--	--	H, 104

LRA Table 3.1.2-4-IP3 is revised as follows.

Tube	Heat transfer	Nickel alloy	Treated borated water (int)	Fouling	Water Chemistry Control – Primary and Secondary	--	--	H, 104
			Treated water (ext)	Fouling	Water Chemistry Control – Primary and Secondary	--	--	H, 104

Audit Item 191

LRA Section 3.1.2.2.1, second paragraph is replaced with the following.

> Evaluation of the fatigue TLAA for the Class 1 portions of the reactor coolant pressure boundary piping and components, including those for interconnecting systems, is discussed in Section 4.3.1. Cracking, including cracking due to fatigue, will be managed by the Inservice Inspection Program.

Audit Item 192

LRA Table 3.1.2-4-IP2 is revised as follows.

Feedwater nozzle	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Steam outlet nozzle	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Secondary manway (upper shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104

Secondary manway cover	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Secondary handhole and inspection port, inspection port threaded plug	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Secondary handhole and inspection port cover	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Secondary shell drain connection	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Instrument connections: steam drum pressure, narrow range water level, and wide range water level	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Blowdown pipe connection (nozzle)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104

LRA table 3.1.2-4-IP3 is revised as follows.

Feedwater nozzle	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Steam outlet nozzle	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Secondary manway (upper shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Secondary manway cover	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Secondary handhole and inspection port, inspection port threaded plug	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Secondary handhole and inspection port cover	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Secondary shell drain connection	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104
Instrument connections: steam drum pressure, narrow range	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C, 104

water level, wide range water level, and sampling								
Blowdown pipe connection (nozzle)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	IV.D2-8 (R-224)	3.1.1-12	C<u>, 104</u>

<u>Audit Item 198</u>

LRA Table 3.1.2-1-IP2 is revised as follows.

Vessel internal attachments • core support lugs (pads)	Structural support	Nickel alloy	Treated borated water (ext)	Cracking	Water Chemistry Control – Primary and Secondary Nickel Alloy Inspection <u>Inservice Inspection</u>	IV.A2-12 (R-88)	3.1.1-31	E

LRA Table 3.1.2-1-IP3 is revised as follows.

Vessel internal attachments • core support lugs (pads)	Structural support	Nickel alloy	Treated borated water (ext)	Cracking	Water Chemistry Control – Primary and Secondary Nickel Alloy Inspection <u>Inservice Inspection</u>	IV.A2-12 (R-88)	3.1.1-31	E

Audit Item 200

LRA Section 3.1.2.2.16 is revised as follows.

3.1.2.2.16 Cracking due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking

1. Cracking due to SCC in stainless steel control rod drive head penetration components and on the primary coolant side of steel steam generator heads clad with stainless steel is managed by the Water Chemistry Control – Primary and Secondary and Inservice Inspection Programs. IPEC will apply NRC orders, bulletins, generic letters, and staff-accepted industry guidelines associated with nickel alloys to steam generator tubesheet primary side, if applicable. Cracking of nickel alloy control rod drive head penetration components due to PWSCC is managed by the Water Chemistry Control – Primary and Secondary, Inservice Inspection and Reactor Vessel Head Penetration Inspection Programs. The Reactor Vessel Head Penetration Inspection Program implements the applicable NRC Orders and will implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines. UFSAR Supplement, Appendix A, Sections A.2.1.30 and A.3.1.30 provide a commitment for this program. For the steam generator tubesheets, cracking is managed by the Water Chemistry Control – Primary and Secondary and Steam Generator Integrity Programs.

Audit Item 201

LRA Table 3.1.1, Item 3.1.1-52, discussion is revised as follows.

~~Not applicable.~~
High strength low alloy steel is not used for these bolting applications at IPEC. ~~Applied stress for stainless steel closure bolting applications should be much less than 100 ksi.~~ Consequently, cracking of bolting due to stress corrosion cracking is not an aging mechanism requiring management. Industry operating experience indicates that loss of material due to wear is not a significant aging effect for this bolting. Occasional thread failures due to wear related mechanisms, such as galling, are event driven conditions that are resolved as required. Loss of preload is a design driven effect and not an aging effect requiring management. Bolting at IPEC is standard grade B7 low alloy steel, or similar material, except in rare specialized applications such as where stainless steel bolting is utilized. Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications (> 700ûF) as stated in the ASME Code, Section II, Part D, Table 4. No IPEC bolting operates at > 700^{0}F. Therefore, loss of preload due to stress relaxation (creep) is not an applicable aging effect for the reactor coolant system. Other issues that may result in pressure boundary joint leakage are improper design or maintenance issues. Improper bolting application (design) and maintenance issues are current plant operational concerns and not related to aging effects or mechanisms that require management during the period of extended operation. Nevertheless, the Bolting Integrity Program manages loss of preload for all external bolting in the reactor coolant system with the exception of the reactor vessel studs. As described in the Bolting Integrity Program, IPEC has taken actions to address NUREG–1339, *Resolution to Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*. These actions include implementation of good

bolting practices in accordance with EPRI NP-5067, "Good Bolting Practices." Proper joint preparation and make-up in accordance with industry standards is expected to preclude loss of preload. This has been confirmed by operating experience at IPEC.

Audit Item 202

LRA Table 3.1.1 is revised as follows.

3.1.1-59	Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	The steam outlet nozzle contains a nickel alloy flow restrictor and is exposed only to high quality steam, consequently this nozzle is not susceptible to flow accelerated corrosion. The feedwater nozzle contains a nickel alloy thermal sleeve that isolates most of the carbon steel nozzles from fluid flow. However, a small portion of the feedwater nozzle next to the feedwater piping is exposed to feedwater flow and is susceptible to flow accelerated corrosion.~~The steam outlet nozzle contains a nickel alloy flow restrictor and the feedwater nozzle contains a nickel alloy thermal sleeve that isolate the carbon steel nozzles from high fluid velocities; therefore these components are not susceptible to FAC~~.

LRA Table 3.1.2-4-IP2 is revised as follows.

Feedwater nozzle	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Flow accelerated corrosion	IV.D2-7	3.1.1-59	A

LRA Table 3.1.2-4-IP3 is revised as follows.

Feedwater nozzle	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Flow accelerated corrosion	IV.D2-7	3.1.1-59	A

Audit Item 203

LRA Table 3.1.1 is revised as follows.

3.1.1-62	Stainless steel, steel with stainless steel cladding reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD)	No	Cracking due to cyclic loading is addressed in other items as cracking due to fatigue. The Inservice Inspection Program manages cracking of stainless steel piping > 4" nps.~~This line was not used. Cracking due to cyclic loading is addressed in other items as cracking due to fatigue. Nevertheless, the Inservice Inspection Program manages cracking of stainless steel piping > 4" nps.~~

LRA Table 3.1.2-3-IP2 is revised as follows.

Piping > 4" nps	Pressure boundary	Stainless steel	Treated borated water > 140ûF (int)	Cracking	Inservice Inspection Water Chemistry Control – Primary and Secondary	IV.C2-2 (R-07) IV.C2-26 (R-56)	3.1.1-68 3.1.1-62	E

LRA Table 3.1.2-3-IP3 is revised as follows.

Piping > 4" nps	Pressure boundary	Stainless steel	Treated borated water > 140ûF (int)	Cracking	Inservice Inspection Water Chemistry Control – Primary and Secondary	IV.C2-2 (R-07) IV.C2-26 (R-56)	3.1.1-68 3.1.1-62	E

Audit Item 205

LRA Table 3.1.2-1-IP2 is revised as follows.

Nozzle safe ends and welds • inlet / outlet safe end welds	Pressure boundary	Nickel alloy	Treated borated water (int)	Cracking	Water Chemistry Control – Primary and Secondary Nickel Alloy Inspection <u>Inservice Inspection</u>	IV.A2-18 (R-90)	3.1.1-65	E
Nozzle safe ends and welds • closure head vent	Pressure boundary	Nickel alloy	Treated borated water (int)	Cracking	Water Chemistry Control – Primary and Secondary Nickel Alloy Inspection <u>Inservice Inspection</u>	IV.A2-18 (R-90)	3.1.1-65	E

LRA Table 3.1.2-1-IP3 is revised as follows.

Nozzle safe ends and welds • inlet / outlet safe end welds	Pressure boundary	Nickel alloy	Treated borated water (int)	Cracking	Water Chemistry Control – Primary and Secondary Nickel Alloy Inspection <u>Inservice Inspection</u>	IV.A2-18 (R-90)	3.1.1-65	E
Nozzle safe ends and welds • closure head vent	Pressure boundary	Nickel alloy	Treated borated water (int)	Cracking	Water Chemistry Control – Primary and Secondary Nickel Alloy Inspection <u>Inservice Inspection</u>	IV.A2-18 (R-90)	3.1.1-65	E

<u>Audit Item 209</u>

LRA Table 3.1.1 is revised as follows.

3.1.1-74	Chrome plated steel, stainless steel, nickel alloy steam generator antivibration bars exposed to secondary feedwater/ steam	Cracking due to stress corrosion cracking, loss of material due to crevice corrosion and fretting	Steam Generator Tube Integrity and Water Chemistry	No	Consistent with NUREG-1801 ~~for some components~~. The Water Chemistry Control – Primary and Secondary and Steam Generator Integrity Programs manage cracking and loss of material of stainless steel and nickel alloy steam generator components exposed to secondary feedwater and steam. ~~For some components, loss of material is managed by the Water Chemistry Control – Primary and Secondary Program. The One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program.~~

LRA Table 3.1.2-4-IP3 is revised as follows.

Secondary handhole cover RTD boss	Pressure boundary	Nickel alloy	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary <u>Steam Generator Integrity Program</u>	IV.D1-15 (RP-15)	3.1.1-74	~~E~~ <u>A, 104</u>
				Cracking	Water Chemistry Control – Primary and Secondary <u>Steam Generator Integrity Program</u>	IV.D2-9 (R-36)	3.1.1-84	A, 104
Secondary handhole cover RTD well	Pressure boundary	Stainless steel	Treated water > 140ûF (int)	Loss of material	Water Chemistry Control – Primary and Secondary <u>Steam Generator Integrity Program</u>	VIII.D1-4 (SP-16)	3.4.1-16	C<u>, 104</u>
				Cracking	Water Chemistry Control – Primary and Secondary <u>Steam Generator Integrity Program</u>	IV.D1-14 (RP-14)	3.1.1-74	~~E~~ <u>A, 104</u>

Audit Item 211

LRA Table 3.1.2-3-IP2 is revised as follows.

Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated borated water > 140ûF (ext)	Cracking	Water Chemistry Control – Primary and Secondary	VII.E1-5 (A-84)	3.3.1-8	E, 104
			Treated borated water > 140ûF (int)	Cracking	Water Chemistry Control – Primary and Secondary	VII.E1-5 (A-84)	3.3.1-8	E, 104

LRA Table 3.1.2-3-IP3 is revised as follows.

Heat exchanger (tubes)	Pressure boundary	Stainless steel	Treated borated water > 140ûF (ext)	Cracking	Water Chemistry Control – Primary and Secondary	VII.E1-5 (A-84)	3.3.1-8	E, 104
			Treated borated water > 140ûF (int)	Cracking	Water Chemistry Control – Primary and Secondary	VII.E1-5 (A-84)	3.3.1-8	E, 104

Audit Item 212

LRA Table 3.1.2-4-IP2 is revised as follows.

Steam Generator Instrumentation								
Piping	Pressure boundary	Stainless steel	Treated water > 140ûF (int)	Loss of material	Water Chemistry Control – Primary and Secondary	VIII.D1-4 (SP-16)	3.4.1-16	C, 104
				Cracking	Water Chemistry Control – Primary and Secondary	VIII.D1-5 (SP-17)	3.4.1-14	C, 104
Tubing	Pressure boundary	Stainless steel	Treated water > 140ûF (int)	Loss of material	Water Chemistry Control – Primary and Secondary	VIII.D1-4 (SP-16)	3.4.1-16	C, 104
				Cracking	Water Chemistry Control – Primary and Secondary	VIII.D1-5 (SP-17)	3.4.1-14	C, 104
Valve body	Pressure boundary	Stainless steel	Treated water > 140ûF (int)	Loss of material	Water Chemistry Control – Primary and Secondary	VIII.D1-4 (SP-16)	3.4.1-16	C, 104
				Cracking	Water Chemistry Control – Primary and Secondary	VIII.D1-5 (SP-17)	3.4.1-14	C, 104

LRA Table 3.1.2-4-IP3 is revised as follows.

Steam Generator Instrumentation								
Piping	Pressure boundary	Stainless steel	Treated water > 140ûF (int)	Loss of material	Water Chemistry Control – Primary and Secondary	VIII.D1-4 (SP-16)	3.4.1-16	C, 104
				Cracking	Water Chemistry Control – Primary and Secondary	VIII.D1-5 (SP-17)	3.4.1-14	C, 104
Tubing	Pressure boundary	Stainless steel	Treated water > 140ûF (int)	Loss of material	Water Chemistry Control – Primary and Secondary	VIII.D1-4 (SP-16)	3.4.1-16	C, 104

				Cracking	Water Chemistry Control – Primary and Secondary	VIII.D1-5 (SP-17)	3.4.1-14	C, 104
Valve body	Pressure boundary	Stainless steel	Treated water > 140ûF (int)	Loss of material	Water Chemistry Control – Primary and Secondary	VIII.D1-4 (SP-16)	3.4.1-16	C, 104
				Cracking	Water Chemistry Control – Primary and Secondary	VIII.D1-5 (SP-17)	3.4.1-14	C, 104

Audit Item 224

LRA Table 3.3.2-2-IP2 is revised as follows (affected rows only are shown).

Piping	Pressure boundary	Carbon steel	Air – indoor (ext)	Loss of material	External Surfaces Monitoring	VII.I-8 (A-77)	3.3.1-58	A
Piping	Pressure boundary	Carbon steel	Air – indoor (int)	Loss of material	External Surfaces Monitoring	V.A-19 (D2-16)	3.2.1-32	E
~~Piping~~	~~Pressure boundary~~	~~Carbon steel~~	~~Conden sation (int)~~	~~Loss of material~~	~~External Surfaces Monitoring~~	~~VII.F1-3 (A-08)~~	~~3.3.1-72~~	~~E~~

LRA Table 3.3.2-2-IP3 is revised as follows (affected rows only are shown).

Piping	Pressure boundary	Carbon steel	Air – indoor (ext)	Loss of material	External Surfaces Monitoring	VII.I-8 (A-77)	3.3.1-58	A
Piping	Pressure boundary	Carbon steel	Air – indoor (int)	Loss of material	External Surfaces Monitoring	V.A-19 (D2-16)	3.2.1-32	E
~~Piping~~	~~Pressure boundary~~	~~Carbon steel~~	~~Conden sation (int)~~	~~Loss of material~~	~~External Surfaces Monitoring~~	~~VII.F1-3 (A-08)~~	~~3.3.1-72~~	~~E~~

Audit Item 226

LRA Table 3.3.2-1-IP2 is revised as follows.

Neutron absorber (boraflex)	Neutron absorption	Boron carbide / elastomer	Treated borated water	Loss of material	Boraflex Monitoring Water Chemistry Control – Primary and Secondary	VII.A2-4 (A-86)	3.3.1-87	~~E~~B
Neutron absorber (boraflex)	Neutron absorption	Boron carbide / elastomer	Treated borated water	Change in material properties	Boraflex Monitoring Water Chemistry Control – Primary and Secondary	VII.A2-4 (A-86)	3.3.1-87	B
Neutron absorber (boraflex)	Neutron absorption	Boron carbide / elastomer	Treated borated water	Cracking	Boraflex Monitoring Water Chemistry Control – Primary and Secondary	VII.A2-4 (A-86)	3.3.1-87	~~E~~B

Audit Item 227

LRA Section 3.3.2.2.6 is revised as follows.

3.3.2.2.6 Reduction of Neutron-Absorbing Capacity and Loss of Material due to General Corrosion

Reduction of neutron-absorbing capacity, change in material properties, and loss of material due to general corrosion are aging effects requiring management for Boral spent fuel storage racks exposed to a treated borated water environment. The aging effect reduction of neutron absorption capacity has not been an observed aging effect at IPEC. These aging effects are managed by the Boral Surveillance Program. This program uses coupon samples to periodically monitor physical and chemical properties of the absorber material. The Boral Surveillance Program is supplemented by the Water Chemistry Control – Primary and Secondary Program.

LRA Table 3.3.2-1-IP3 is revised to add the following line item.

Neutron absorber (boral)	Neutron absorption	Boron carbide / aluminum	Treated borated water	Change in material properties	Boral Surveillance Water Chemistry Control – Primary and Secondary	VII.A2-5 (A-88)	3.3.1-13	E

Audit Item 231

LRA Section A.2.1.26, One-Time Inspection Program, 4th paragraph, is revised as follows.

> A one-time inspection activity is used to verify the effectiveness of the Oil Analysis Program by confirming that unacceptable cracking, loss of material and fouling are not occurring on components within systems covered by the Oil Analysis Program [Section A.2.1.25].

LRA Section A.3.1.26, One-Time Inspection Program, 4th paragraph, will be revised as follows.

> A one-time inspection activity is used to verify the effectiveness of the Oil Analysis Program by confirming that unacceptable cracking, loss of material and fouling are not occurring on components within systems covered by the Oil Analysis Program [Section A.3.1.25].

Audit Item 232

LRA Table 3.3.2-14-IP2 is revised as follows.

~~Expansion joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Exhaust gas (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~--~~	~~--~~	~~H~~

LRA Table 3.3.2-14-IP3 is revised as follows.

~~Expansion joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Exhaust gas (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~--~~	~~--~~	~~H~~

LRA Table 3.3.2-16-IP2 is revised as follows.

~~Flexible connection~~	~~Pressure boundary~~	~~Stainless steel~~	~~Exhaust gas (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~--~~	~~--~~	~~H~~

Audit Item 233

LRA Table 3.3.2-19-1-IP2 is revised as follows.

~~Flex joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Steam (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~--~~	~~--~~	~~G~~
~~Flex joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Treated water > 140°F (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~VII.E1-16 (A-57)~~	~~3.3.1-2~~	~~C, 302~~

LRA Table 3.3.2-19-4-IP2 is revised as follows.

~~Expansion joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Steam (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~--~~	~~--~~	~~H~~

LRA Table 3.3.2-19-12-IP2 is revised as follows.

Sight glass	Pressure boundary	Carbon steel	Treated water (int)	Cracking – fatigue	~~TLAA – metal fatigue~~One-time inspection	VIII.D1-7 (S-11)	3.4.1-1	E

LRA Table 3.3.2-19-23-IP2 is revised as follows.

~~Expansion joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Steam (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~--~~	~~--~~	~~H~~
~~Expansion joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Treated water > 140°F (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~VII.E1-16 (A-57)~~	~~3.3.1-2~~	~~C, 302~~

LRA Table 3.3.2-19-2-IP3 is revised as follows.

Sight glass	Pressure boundary	Carbon steel	Treated water (int)	Cracking – fatigue	~~TLAA – metal fatigue~~One-time inspection	VIII.B1-10 (S-08)	3.4.1-1	E, 309

LRA Table 3.3.2-19-14-IP3 is revised as follows.

~~Expansion joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Treated water > 140°F (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~VII.E1-16 (A-57)~~	~~3.3.1-2~~	~~C, 302~~
Sight glass	Pressure boundary	Carbon steel	Treated water (int)	Cracking – fatigue	~~TLAA – metal fatigue~~One-time inspection	VIII.D1-7 (S-11)	3.4.1-1	E

LRA Table 3.3.2-19-18-IP3 is revised as follows.

~~Expansion joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Steam (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~--~~	~~--~~	~~H~~

LRA Table 3.3.2-19-23-IP3 is revised as follows.

~~Expansion joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Steam (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~--~~	~~--~~	~~H~~
~~Expansion joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Treated water > 140°F (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~VII.E1-16 (A-57)~~	~~3.3.1-2~~	~~C, 302~~

LRA Table 3.3.2-19-27-IP3 is revised as follows.

~~Expansion joint~~	~~Pressure boundary~~	~~Stainless steel~~	~~Steam (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~--~~	~~--~~	~~H~~
Sight glass	Pressure boundary	Carbon steel	Steam (int)	Cracking – fatigue	~~TLAA – metal fatigue~~One-time inspection	VIII.B1-10 (S-08)	3.4.1-1	E

LRA Table 3.4.1 is revised as follows.

3.4.1-1	Steel piping, piping components, and piping elements exposed to steam or treated water	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA	For most components, ~~F~~fatigue is a TLAA. For some components, where no fatigue analyses exist, the One-Time Inspection program will confirm the absence of significant cracking due to fatigue. See Section 3.4.2.2.1.

LRA Section 3.4.2.2.1, Cumulative Fatigue Damage, is revised as follows.

Where identified as an aging effect requiring management, the analysis of fatigue is a TLAA as defined in 10 CFR 54.3. TLAAs are evaluated in accordance with 10 CFR 54.21(c). Evaluation of this TLAA is addressed in Section 4.3. For some components, where no fatigue analyses exist, the One-Time Inspection program will confirm the absence of significant cracking due to fatigue using enhanced visual or other NDE techniques.

Audit Item 235

LRA Section 3.0, Aging Management Review Results, will be revised as follows.

FURTHER EVALUATION REQUIRED

The Table 1s in NUREG-1801 indicate that further evaluation is necessary for certain aging effects and other issues discussed in NUREG-1800 (Reference 3.0-1). Section 3 includes discussions of these issues numbered in accordance with the discussions in NUREG-1800. The discussions explain the site's approach to these areas requiring further evaluation.

CRITERIA FOR IDENTIFICATION OF ONE TIME INSPECTION PROGRAM

The following criteria apply for including the One-Time Inspection Program in a Table 2 line item of the LRA.

• When the intent is to confirm that an aging effect is not occurring or the aging effect is occurring very slowly as not to affect the component or structure intended function such that an aging management program is not warranted, the One-Time Inspection Program will be listed in the aging management program column.

• If the associated line item in NUREG-1801 Vol. 2 specifies a program to verify the effectiveness of a listed program, then a plant-specific note will be included in the line item that states "The One-Time Inspection Program will verify effectiveness of the XXX program". One-Time Inspection will not be listed in the aging management program column.

• If the associated line item in NUREG-1801 Vol. 2 does not specify the One-Time Inspection Program to verify effectiveness of the associated program, then only the program will be identified with no plant-specific note.

Audit Item 237

LRA Section B.1.15, Flow Accelerated Corrosion Program Description, second paragraph, is revised as follows.

The program, based on EPRI guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R3 for an effective flow-accelerated corrosion program, predicts, detects, and monitors FAC in plant piping and other pressure-retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions, or repair or replace components as necessary. The aging effect of loss of material managed by the Flow Accelerated Corrosion Program is equivalent to the aging effect of wall thinning as defined in NUREG-1801 Volume 2 Table IX.E.

LRA Section A.2.1.14, second paragraph, is revised as follows.

The program, based on EPRI guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R3 for an effective flow-accelerated corrosion program, predicts, detects, and monitors FAC in plant piping and other pressure retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions. The program specifies repair or replacement of components as necessary. The aging effect of loss of material managed by the Flow Accelerated Corrosion Program is equivalent to the aging effect of wall thinning as defined in NUREG-1801 Volume 2 Table IX.E.

LRA Section A.3.1.14, second paragraph, is revised as follows.

The program, based on EPRI guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R3 for an effective flow-accelerated corrosion program, predicts, detects, and monitors FAC in plant piping and other pressure retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions. The program specifies repair or replacement of components as necessary. The aging effect of loss of material managed by the Flow Accelerated Corrosion Program is equivalent to the aging effect of wall thinning as defined in NUREG-1801 Volume 2 Table IX.E.

Audit Item 240

LRA Section A.2.1.28 will be revised as follows.

Surveillance testing and periodic inspections using visual or other non-destructive examination techniques verify that the following components are capable of performing their intended function.

- reactor building cranes (polar and manipulator), crane rails, and girders, and refueling platform
- recirculation pump motor cooling coils and housing
- city water system components
- charging pump casings
- plant drain components and backwater valves
- station air containment penetration piping
- HVAC duct flexible connections
- HVAC stored portable blowers and flexible trunks
- EDG exhaust components
- EDG duct flexible connections
- EDG air intake and aftercooler components
- EDG air start components
- EDG cooling water makeup supply valves
- security generator exhaust components
- security generator radiator tubes
- SBO/Appendix R diesel exhaust components

- SBO/Appendix R diesel turbocharger and aftercooler
- SBO/Appendix R jacket water heat exchanger
- SBO/Appendix R diesel fuel oil cooler
- diesel fuel oil trailer transfer tank and associated valves
- auxiliary feedwater components
- containment cooling duct flexible connections
- containment cooling fan units internals
- control room HVAC condensers and evaporators
- control room HVAC ducts and drip pans
- control room HVAC duct flexible connections
- circulating water, city water, intake structure system, emergency diesel generator, fresh water cooling, instrument air, integrated liquid waste handling, lube oil, miscellaneous, radiation monitoring, river water, station air, waste disposal, and water treatment plant system piping, piping components, and piping elements
- pressurizer relief tank
- <u>main steam safety valve tailpipes</u>
- <u>atmospheric dump valve silencers</u>

LRA Section A.3.1.28 is revised as follows.

Surveillance testing and periodic inspections using visual or other non-destructive examination techniques verify that the following components are capable of performing their intended function.

- reactor building cranes (polar and manipulator), crane rails, and girders, and refueling platform
- containment spray system sodium hydroxide tank
- recirculation pump motor cooling coils and housing
- city water system components
- charging pump casings
- plant drain components
- station air containment penetration piping
- HVAC duct flexible connections
- HVAC stored portable blowers and flexible trunks
- EDG exhaust components
- EDG duct flexible connections
- EDG air intake and aftercooler components
- EDG air start components
- EDG cooling water makeup supply valves
- security generator exhaust components
- security generator radiator tubes
- Appendix R diesel generator exhaust components
- Appendix R diesel generator radiator
- Appendix R diesel generator aftercooler
- Appendix R diesel generator starting air components
- Appendix R diesel generator crankcase exhaust components

- diesel fuel oil trailer transfer tank and associated valves
- auxiliary feedwater components
- containment cooling duct flexible connections
- containment cooling fan units internals
- control room HVAC condensers and evaporators
- control room HVAC ducts and drip pans
- control room HVAC duct flexible connections
- chlorination, circulating water, city water makeup, emergency diesel generator, floor drain, gaseous waste disposal, instrument air, liquid waste disposal, nuclear equipment drain, river water, station air piping, steam generator sampling, and secondary plant sampling piping components, and piping elements
- pressurizer relief tank
- main steam safety valve tailpipes
- atmospheric dump valve silencers

LRA Section B.3.1.29, Program Description, is revised as follows.

Main steam system	Use visual or other NDE techniques to inspect a representative sample of the internal surfaces of the carbon steel main steam safety valve tailpipes and atmospheric dump valve silencers to manage loss of material.

LRA Table 3.4.1 is revised as follows.

3.4.1-30	Steel piping, piping components, and piping elements exposed to air outdoor (internal) or condensation (internal)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	~~The only s~~Steel components with intended functions in the steam and power conversion systems with internal surfaces exposed to outdoor air or condensation are the condensate storage tanks, main steam safety valve (MSSV) tailpipes, and the atmospheric dump valve (ADV) silencers. The condensate storage tank vapor space is nitrogen blanketed but the environment is conservatively assumed to be condensation. Loss of material for the~~se~~ tank surfaces is managed by controlling the tank water chemistry with the Water Chemistry Control – Primary and Secondary Program. The One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program. Loss of material for the MSSV tailpipes and the ADV silencers will be managed by the Periodic Surveillance and Preventive Maintenance Program.

LRA Table 3.4.2-1-IP2 is revised as follows.

Piping	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	External Surfaces Monitoring	VIII.B1-6 (SP-59)	3.4.1-30	E

Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring	VIII.H-8 (S-41)	3.4.1-28	A
Silencer	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	External Surfaces Monitoring	VIII.B1-6 (SP-59)	3.4.1-30	E
Silencer	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring	VIII.H-8 (S-41)	3.4.1-28	A

LRA Table 3.4.2-1-IP3 is revised as follows.

Piping	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	External Surfaces Monitoring	VIII.B1-6 (SP-59)	3.4.1-30	E
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring	VIII.H-8 (S-41)	3.4.1-28	A
Silencer	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	External Surfaces Monitoring	VIII.B1-6 (SP-59)	3.4.1-30	E
Silencer	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring	VIII.H-8 (S-41)	3.4.1-28	A

Audit Item 241

LRA Table 3.3.1, Item 3.3.1-45, discussion is revised as follows.

Loss of preload is a design-driven effect and not an aging effect requiring management. Bolting at IPEC is standard grade B7 low alloy steel, or similar material, except in rare specialized applications such as where stainless steel bolting is utilized. Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications (> 700°F), as stated in the ASME Code, Section II, Part D, Table 4. No bolting operates at > 700°F. Therefore, loss of preload due to stress relaxation (creep) is not an applicable aging effect for auxiliary systems. Other issues such as gasket creep and loosening that may result in pressure boundary joint leakage are improper design or maintenance issues. Improper bolting application (design) and maintenance issues are current plant operational concerns and not related to aging effects or mechanisms that require management during the period of extended operation. Nevertheless, the Bolting Integrity Program manages loss of preload for all bolting in auxiliary systems. As described in the Bolting Integrity Program, IPEC has taken actions to address NUREG–1339, *Resolution to Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*. These actions include implementation of good bolting practices in accordance with EPRI NP-5067, Good Bolting Practices. Proper joint preparation and make-up in accordance with industry standards is expected to preclude loss of preload. This has been confirmed by operating experience at IPEC.

LRA Table 3.4.1, Item 3.4.1-22, discussion is revised as follows.

Consistent with NUREG-1801 for bolting susceptible to loss of material. The Bolting Integrity Program manages the loss of material for steel bolting. Loss of preload is not an applicable aging effect. Loss of preload is a design-driven effect and not an aging effect requiring management. Bolting at IPEC is standard grade B7 low alloy steel, or similar material, except in rare specialized applications such as where stainless steel bolting is utilized. Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications (> 700°F), as stated in the ASME Code, Section II, Part D, Table 4. No IPEC bolting operates at > 700°F. Therefore, loss of preload due to stress relaxation (creep) is not an applicable aging effect for steam and power conversion systems. Other issues such as gasket creep and self loosening that may result in pressure boundary joint leakage are improper design or maintenance issues. Improper bolting application (design) and maintenance issues are current plant operational concerns and not related to aging effects or mechanisms that require management during the period of extended operation. <u>Nevertheless, the Bolting Integrity Program manages loss of preload for all bolting in the steam and power conversion systems</u>. As described in the Bolting Integrity Program, IPEC has taken actions to address NUREG–1339, *Resolution to Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*. These actions include implementation of good bolting practices in accordance with EPRI NP-5067, Good Bolting Practices. Proper joint preparation and make-up in accordance with industry standards is expected to preclude loss of preload. This has been confirmed by operating experience at IPEC.

<u>Audit Item 258</u>

LRA Table 3.5.1, Item 3.5.1-6, is revised as follows.

3.5.1-6	Steel elements: steel liner, liner anchors, integral attachments	Loss of material due to general, pitting and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	Yes, if corrosion is significant for inaccessible areas	CII-IW~~L~~E, Containment Leak Rate and Structures Monitoring Programs will manage this aging effect. For further discussion, see Section 3.5.2.2.1.4.

<u>Audit Item 267</u>

LRA Table 3.2.2-1-IP2 is revised as follows.

~~Flex hose~~	~~Pressure boundary~~	~~Stainless steel~~	~~Treated borated water > 140°F (int)~~	~~Cracking – fatigue~~	~~TLAA – metal fatigue~~	~~V.D1-27 (E-13)~~	~~3.2.1-1~~	~~A~~

Audit Item 270

LRA Table 3.2.1, Item 3.2.1-24, discussion is revised as follows.

Loss of preload is a design-driven effect and not an aging effect requiring management. Most bolting at IPEC is standard grade B7 low alloy steel, or similar material, except in specialized applications such as where stainless steel bolting is utilized. Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications (> 700°F) as stated in the ASME Code, Section II, Part D, Table 4. No IPEC bolting operates at > 700°F. Therefore, loss of preload due to stress relaxation (creep) is not an applicable aging effect for ESF systems. Other issues that may result in pressure boundary joint leakage are improper design or maintenance issues. Improper bolting application (design) and maintenance issues are current plant operational concerns and not related to aging effects or mechanisms that require management during the period of extended operation. Nevertheless, the Bolting Integrity Program manages loss of preload for all bolting in ESF systems. As described in the Bolting Integrity Program, IPEC has taken actions to address NUREG–1339, *Resolution to Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*. These actions include implementation of good bolting practices in accordance with EPRI NP-5067, "Good Bolting Practices." Proper joint preparation and make-up in accordance with industry standards is expected to preclude loss of preload. This has been confirmed by operating experience at IPEC.

Audit Item 356

LRA A.3.1.28, Periodic Surveillance and Preventive Maintenance, second paragraph, is revised as follows.

Surveillance testing and periodic inspections using visual or other non-destructive examination techniques verify that the following components are capable of performing their intended function.

- reactor building cranes (polar and manipulator), crane rails, and girders, and refueling platform
- containment spray system components and sodium hydroxide tank
- recirculation pump motor cooling coils and housing

LRA B.1.29, Periodic Surveillance and Preventive Maintenance, Program Description, is revised as follows.

Containment spray system	IP3: Perform wall thickness measurements of the NaOH tank to manage loss of material. [existing] <u>IP3: Perform visual or other NDE inspections on the inside surfaces of a representative sample of stainless steel components exposed to sodium hydroxide to manage loss of material and cracking</u>.

<u>Audit Item 357</u>

LRA Table 3.1.2-4-IP2 is revised as follows.

Primary manway cover insert plate	Pressure boundary	Stainless steel	Treated borated water > 140ûF (int)	Cracking	Water Chemistry Control – Primary and Secondary <u>Inservice Inspection</u>	IV.D1-1 (R-07)	3.1.1-68	E

LRA Table 3.1.2-4-IP3 is revised as follows.

Primary manway cover insert plate	Pressure boundary	Stainless steel	Treated borated water > 140ûF (int)	Cracking	Water Chemistry Control – Primary and Secondary <u>Inservice Inspection</u>	IV.D1-1 (R-07)	3.1.1-68	E

ATTACHMENT 2 TO NL-07-153

List of Regulatory Commitments, Revision 1

(This revision supersedes the revision submitted in letter NL-07-039, dated 4-23-2007)

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

List of Regulatory Commitments

Revision 1

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

Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments.

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
1	Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank, and fire water tanks once during the first ten years of the period of extended operation. Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.1 A.3.1.1 B.1.1
2	Enhance the Bolting Integrity Program for IP2 and IP3 to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and clarify the prohibition on use of lubricants containing MoS_2 for bolting. <u>The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.</u>	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.2 A.3.1.2 B.1.2 <u>Audit Items 201, 241, 270</u>
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. <u>This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection.</u>	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.5 A.3.1.5 B.1.6 <u>Audit Item 173</u>

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
4	Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years. Enhance the Diesel Fuel Monitoring Program to include quarterly sampling and analysis of the IP2 SBO/Appendix R diesel generator fuel oil day tank, IP2 security diesel fuel oil day tank, and IP3 Appendix R fuel oil storage tank. Particulates, water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be less than or equal to 10mg/l. Water and sediment acceptance criterion will be less than or equal to 0.05%. Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom surface 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, 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 thé 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. <u>Enhance the Diesel Fuel Monitoring Program to direct samples be taken near the tank bottom and include direction to remove water when detected.</u> <u>Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.</u>	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.8 A.3.1.8 B.1.9 <u>Audit items 128, 129, 132</u>

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

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

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
8	Enhance the Fire Water Program to include inspection of IP2 and IP3 hose reels for evidence of corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation. Enhance the Fire Water Program to replace all or test a sample of IP2 and IP3 sprinkler heads required for 10 CFR 50.48 using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Enhance the Fire Water Program to perform wall thickness evaluations of IP2 and IP3 fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
9	Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate that flux thimble tubes that cannot be inspected over the tube length and cannot be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.15 A.3.1.15 B.1.16

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
10	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include the following heat exchangers in the scope of the program. • Safety injection pump lube oil heat exchangers • RHR heat exchangers • RHR pump seal coolers • Non-regenerative heat exchangers • Charging pump seal water heat exchangers • Charging pump fluid drive coolers • Charging pump crankcase oil coolers • Spent fuel pit heat exchangers • Secondary system steam generator sample coolers • Waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water heat exchanger (IP2 only) Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include consideration of material-environment combinations when determining sample population of heat exchangers. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to establish minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Establish acceptance criteria for heat exchangers visually inspected to include no unacceptable signs of degradation.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.16 A.3.1.16 B.1.17, Audit Item 52

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
11	Enhance the ISI Program for IP2 and IP3 to provide periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump support systems.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.17 A.3.1.17 B.1.18 Audit item 59
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.18 A.3.1.18 B.1.19
13	Enhance the Metal-Enclosed Bus Inspection Program to add IP2 480V bus associated with substation A to the scope of bus inspected. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to inspect bolted connections at least once every five years if performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation. The plant will process a change to applicable site procedure to remove the reference to "re-torquing" connections for phase bus maintenance and bolted connection maintenance.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.19 A.3.1.19 B.1.20 Audit Item 124 Audit Item 133
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.21 A.3.1.21 B.1.22

#	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: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.22 A.3.1.22 B.1.23 Audit item 173
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.23 A.3.1.23 B.1.24 Audit item 173
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.24 A.3.1.24 B.1.25 Audit item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
18	Enhance the Oil Analysis Program for IP2 to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with oil analysis for other site diesel generators. Enhance the Oil Analysis Program for IP2 and IP3 to sample and analyze generator seal oil and turbine hydraulic control oil. Enhance the Oil Analysis Program for IP2 and IP3 to formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of this program. The program will specify corrective actions in the event acceptance criteria are not met. Enhance the Oil Analysis Program for IP2 and IP3 to formalize trending of preliminary oil screening results as well as data provided from independent laboratories.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.25 A.3.1.25 B.1.26
19	Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.26 A.3.1.26 B.1.27 Audit item 173
20	Implement the One-Time Inspection – Small Bore Piping Program for IP2 and IP3 as described in LRA Section B.1.28. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.27 A.3.1.27 B.1.28 Audit item 173
21	Enhance the Periodic Surveillance and Preventive Maintenance Program for IP2 and IP3 as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.28 A.3.1.28 B.1.29

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
22	Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 revising the specimen capsule withdrawal schedules to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation. Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.31 A.3.1.31 B.1.32
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.32 A.3.1.32 B.1.33 Audit item 173
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.34 A.3.1.34 B.1.35
25	Enhance the Structures Monitoring Program to explicitly specify that the following structures are included in the program. • Appendix R diesel generator foundation (IP3) • Appendix R diesel generator fuel oil tank vault (IP3) • Appendix R diesel generator switchgear and enclosure (IP3) • city water storage tank foundation • condensate storage tanks foundation (IP3) • containment access facility and annex (IP3) • discharge canal (IP2/3) • emergency lighting poles and foundations (IP2/3) • fire pumphouse (IP2) • fire protection pumphouse (IP3) • fire water storage tank foundations (IP2/3) • gas turbine 1 fuel storage tank foundation • maintenance and outage building-elevated passageway (IP2)	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.35 A.3.1.35 B.1.36 Audit item 86 Audit item 88 Audit Item 87

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	• 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) • superheater stack • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3) Enhance the Structures Monitoring Program for IP2 and IP3 to clarify that in addition to structural steel and concrete, the following commodities <u>(including their anchorages)</u> are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches and hatch covers • monorails • new fuel storage racks • sumps, sump screens, strainers and flow barriers Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties			

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	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. Samples will be monitored for sulfates, pH and chlorides. 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.			
26	Implement the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.37. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.36 A.3.1.36 B.1.37 Audit item 173
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.37 A.3.1.37 B.1.38 Audit item 173
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 cooling water system pH within limits specified by EPRI guidelines.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.39 A.3.1.39 B.1.40

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	IP2: September 28, 2013	NL-07-039	A.2.1.40 B.1.41
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	IP2: September 28, 2011 IP3: December 12, 2013	NL-07-039	A.2.1.41 A.3.1.41
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.2.1.2 A.3.2.1.2 4.2.3
32	As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS (10 CFR 50.61) rule when approved, which would permit use of Regulatory Guide 1.99, Revision 3.	IP3: December 12, 2015	NL-07-039	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), IP2 and IP3 will implement one or more of the following: (1) Refine the fatigue analyses to determine valid CUFs less than 1 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, including NUREG/CR-6260 locations, with existing fatigue analysis valid for the period of extended operation, use the existing CUF to determine the environmentally adjusted CUF. 2. In addition to the NUREG/CR-6260 locations, more limiting 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) Manage the effects of aging due to fatigue at the affected locations by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method acceptable to the NRC). (3) Repair or replace the affected locations before exceeding a CUF of 1.0. Should IPEC select the option to manage the aging effects due to environmental-assisted fatigue during the period of extended operation, details of the aging management program such as scope, qualification, method, and frequency will be submitted to the NRC at least 2 years prior to the period of extended operation.	IP2: September 28, 2011 IP3: December 12, 2013	NL-07-039 NL-07-153	A.2.2.2.3 A.3.2.2.3 4.3.3 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 50.59(c)(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	April 30, 2008	NL-07-078	2.1.1.3.5

ATTACHMENT 3 TO NL-07-153

AMP Database Report, Revision 1

(This revision supersedes the revision submitted in letter NL-07-124 dated 10-11-2007)

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

Item	Request	Response
1	Section 3.6-1 Describe SBO restoration paths for IP2/IP3. Included appropriate drawings for discussion.	The single line schematics (FSAR Figures 8.2-1 and 8.2-2) were provided for review. As stated in the IPEC LRA, Section 2.5, Page 2.5-2, "The offsite power sources required to support SBO recovery actions are the offsite sources that supply the station auxiliary transformers. Specifically, the offsite power recovery path includes the station auxiliary transformers, the 138KV switchyard circuit breakers supplying the station auxiliary transformers, the circuit breaker-to-transformer and transformer-to-onsite electrical distribution interconnections, and the associated control circuits and structures." Based on IP2 UFSAR Section 8.1.2.1, "10 CFR 50 Appendix A General Design Criterion 17 - Electric Power Systems," IP2 is supplied with normal, standby, and emergency power sources. Offsite (standby) power required during plant startup, shutdown, and after a turbine trip is supplied from the Buchanan Substation by the Con Edison 138 kV system feeders and the 13.8 kV system feeders. The 138 kV feeder is the preferred standby power source and is connected to the 6.9 kV buses through the station auxiliary transformer. The 13.8 kV feeder is the alternate standby power and is connected to the 6.9 kV buses through the GT autotransformer. The Buchanan 13.8 kV system is available for immediate manual connection to the auxiliary buses. The 480 volt engineered safety feature buses are connected to the 6.9 kV buses through station service transformers. LRA Figure 2.5-2 shows the 6.9kV source for Busses 5 and 6 as the 138kV/6.9kV station auxiliary transformer, which is shown connected to two separate 138kV transmission conductors through Breaker F2 and through Breaker BT 4-5. Figure 2.5-2 will be revised to show the 138 kV feeder connection via the station auxiliary transformer and the 13.8 kV feeder connection via the GT autotransformer. The GT autotransformer is connected to the alternate feed from the Buchanan 13.8 kV substation via breaker F2-3. Because breaker BT 4-5 is a connection to IP3 and not a boundary or interface point between the plant and transmission system, Figure 2.5-2 will be revised to show 13.8 kV Breaker F2-3 instead of BT 4-5. Breaker F2-3 is the interface between the plant and the interconnected grid at the Buchanan substation 13.8 kV bus. Figure 2.5-2 will be revised to show motor operated disconnect F3A instead of breaker F2, because breaker F2 is an integral component in the Buchanan substation. F3A is the interface between the plant and the interconnected grid at the Buchanan substation as shown on interface agreement drawings with Con Edison. Based on IP3 UFSAR Section 8.2.1, "Network Interconnection", and 8.2.3, " Emergency Power - Sources Description," IP3 is supplied with normal, standby, and emergency power sources. Offsite (standby) power required during plant startup, shutdown and after a turbine trip is supplied from the Buchanan Substation by the Con Edison 138 kV system feeders and the 13.8 kV system feeders. The 138 kV feeder is the preferred standby power source and is connected to the 6.9 kV buses through the station auxiliary transformer. The 13.8 kV feeder is the alternate standby power and is connected to the 6.9 kV buses through the GT autotransformer. The Buchanan 13.8 kV system is available for immediate manual connection to the auxiliary buses. The 480 volt engineered safety feature buses are connected to the 6.9 kV buses through station service transformers. LRA Figure 2.5-3 shows the 6.9kV source for Busses 5 and 6 as the 138kV/6.9kV station auxiliary transformer, which is shown connected to two separate 138kV transmission conductors through Breaker BT2-6 and through Breaker BT5-6. Figure 2.5-3 will be revised to show the 138 kV feeder connection via the station auxiliary transforme, and the 13.8 kV feeder connection via the GT autotransformer. The GT autotransformer is connected to the alternate feed from the Buchanan 13.8 kV substation via breaker F3-1. Because breaker BT 5-6 is a connection to IP2 and not a boundary or interface point between the plant and transmission system, Figure 2.5-3 will be revised to show Breaker F3-1 instead of Breaker BT 5-6. Breaker F3-1 is the interface between the plant and interconnected grid at the Buchanan substation 13.8 kV bus. Breaker BT 2-6 is the interface between the plant and interconnected grid at the Buchanan substation as shown on the interface agreement drawings with Con Edison Information to be incorporated into the LRA.
2	Section 3.6-2 High voltage direct burial insulated cable (>35 kV)	The only high voltage direct burial insulated cable (>35 kV) is part of the IP2 SBO recovery path. The cable is a portion of the 138 kV path from the Station Aux Transformer to

Item	Request	Response
	may be exposed to condensation and wetting in inaccessible location, such as conduits, cable trenches, cable troughs, duct banks, underground vaults or direct buried installation. When an energized high voltage cable is exposed to wet conditions for which it is not designed, water tree or a decrease in dielectric strength of the conductor insulation can occur. This can potentially lead to electrical failure. Provide a manufacturer certification that 138 kV direct burial insulated transmission cable is qualified for continuous submerge condition or provide an AMP to ensure that water tree aging effect will not degrade the cable intended function during the period of extended operation.	breaker F2 as shown in LRA Figure 2.5-2. This is a lead sheathed solid dielectric insulated cable. The lead sheath prevents moisture in submerged cables from contacting the insulation, so water trees will not be formed. Therefore, there is no aging effect that requires management. The specification for the 138 kV 750 MCM solid dielectric cable states the cable is supplied with a moisture barrier. Radial water sealing is achieved by a corrosion resistant lead sheath. Longitudinal water sealing is achieved by using a water swelling material applied under the lead sheath. The cable passed longitudinal water penetration tests as specified in the applicable AEIC specification. The cable is installed in a pipe-type system, which originally contained an oil-filled cable system. The replacement cable was installed in the same route. This cable was designed with a thick layer of lead over the cable insulation with an overall jacket over the lead and insulation. The construction of this cable differs from the typical medium voltage cable design of insulation with an overall jacket. This type of cable is used in transmission substation networks to maximize the life of the cable, which is mainly associated with the good characteristics in moisture environments, and the dielectric constant requirements of a 138 kV feeder cable. *The AEIC CS7 specification is for lead sheath power* (69 kV *to* 138 kV) *cables* designed to be installed in wet environments for extended periods. The insulation system for this cable is a cross-linked polyethylene (XLPE). The lead sheath combined with the overall jacket provides a virtually impenetrable barrier against hostile environments – liquids, fire hydrocarbons, acids, caustic, sewage, etc. The license renewal electrical handbook states lead sheath cables prevent the effects of moisture on the cable insulation.. A lead sheathed cable is comparable to a submarine cable. A review of the IP2 and IP3 operating experience did not identify any failures of the 138kV solid dielectric underground transmission cables. Interviews with knowledgeable plant staff did not identify any additional IP2 or IP3 operating experience with these cables. Additional searches of industry operating experience did not identify any failures for this type of transmission cable. Based on the above, the aging effects caused by moisture and voltage stress is not applicable to this cable. This 138 kV underground cable, which is part of the IP2 offsite power path, does not have any aging effects that require management; therefore, this cable is not included in the scope of the Non-EQ Inaccessible Medium-Voltage Cable program.
20	AMP B.1.3-1 (Boraflex Monitoring) According to GALL, the applicant's Boraflex Monitoring Program, according to manufacture's recommendations, should assure that no unexpected degradation occurs that would compromise the criticality analysis. What are the manufacturer's recommendations for IP-2 AND IP-3?	The boraflex manufacturer was Brand Industrial Services Corporation who no longer supports the product. The recommendations for management of boraflex at IP2 are derived from industry experience and responses to NRC GL 96-04, Boraflex Degradation in Spent Fuel Pool Storage Racks. Boraflex is not used for criticality control of the IP3 spent fuel pool.
21	AMP B.1.3-2 (Boraflex Monitoring) What is the justification for IPEC selection of areal density measurement over GALL specification for measuring gap formation by blackness testing.	Areal density testing provides a direct measurement of in-rack performance of boraflex panels through measurement of gaps, erosion, and general thinning. Blackness testing provides only an indication of neutron absorber presence and does not quantitatively measure the Boron-10 areal density of neutron absorber in each rack. Therefore, areal density along with the monitoring of silica levels in the spent fuel pool provides adequate detection of boraflex degradation.
24	AMP B.1.5-3 (Boric Acid Corrosion) Discuss how the applicant responded to the NRC' s order and bulletins listed below; explain how these responses have been used to update the component list location and visual inspection within the scope of the Boric Acid Corrosion Program. NRC Bulletin 2002-01 dated March 29 and May	IPEC responses to the referenced NRC generic communications are contained in the letters referenced below. Copies of the letters were available on site for review or in ADAMS. Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity" This bulletin was issued to alert licensees of the significant corrosion of the Davis Besse reactor vessel head which resulted from through-wall CRDM nozzle leakage. Licensees were required to review their GL 88-05 boric acid inspection programs to ensure effectiveness in detecting corrosion at RCS locations where Alloy 600 could

Item	Request	Response
	16, 2002 NRC RAI on Bulletin 2002-01 dated January 17, 2003 NRC Bulletin 2003-02 dated September 19, 2003 NRC Order EA 03 009, dated March 3, April 11 and April 18, 2003 NRC Bulletin 2004 - 01, dated May 28, 2004	crack and result in accumulation of wet boron. In response to this bulletin, both IP2 and IP3 committed to review their boric acid corrosion prevention programs as originally required by GL 88-05. Procedures 2PT-R156, "RCS Boric Acid Leakage and Corrosion Inspection", 3-PT-R114A, "Reactor Vessel and Closure Head Boric Acid Leakage and Corrosion Inspection", and 3-PT-R114, "RCS Boric Acid Leakage and Corrosion Inspection" were revised to include inspection for signs of leakage or boron deposits detected during bare metal visual inspections of the reactor vessel head near the CRDM nozzles. The procedures also warn that signs of possible RCS leakage may include boron or rust on containment radiation monitor filters, FCU cooling fins, and some parts of containment. Refer to the following letters for bulletin response specifics. NL-02-050/IPN-02-023, "Submittal of 15 Day Response to NRC Bulletin 2002-01" NL-02-074/IPN-02-039, "Submittal of 60 Day Response to NRC Bulletin 2002-01" NL-02-099/IPN-02-060, "Supplement to 15 Day Response for NRC Bulletin 2002-01" NRC RAI on Bulletin 2002-01 This RAI further outlined the requirements of a comprehensive boric acid corrosion control program. Refer to the following letter for response specifics. NL-03-020, "Response to Request for Additional Information Regarding the 60-day Response to NRC Bulletin 2002-01" NRC Bulletin 2003-02 This bulletin informed facilities that current methods of inspecting the reactor pressure vessel (RPV) lower heads may need to be supplemented with bare-metal visual inspections in order to detect reactor coolant pressure boundary leakage. The bulletin also requested licensees provide the NRC with information related to inspections that have been performed to verify the integrity of the RPV lower head penetrations. IP2 and IP3 reported that bare metal visual inspection of lower head penetrations revealed no evidence of pressure boundary leakage. Procedures 2-PT-R204, "Visual Inspection of Reactor Vessel Bottom Mounted Instrumentation Penetrations for Leakage" and 3-PT-R204, "Visual Inspection of Reactor Vessel Bottom Mounted Instrumentation Penetrations for Leakage" were developed to meet the requirements of this bulletin. Refer to the following letters from the NRC acknowledging completion of the bulletin requirements. COR-05-02835, "Indian Point Unit 2 – Response to NRC Bulleting 2003-02, " Leakage From Reactor Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity"" COR-05-02892, "Indian Point Unit 3 – Response to NRC Bulleting 2003-02, " Leakage From Reactor Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity"" First Revised Order EA-03-009 This order extended the region of the CRDM considered susceptible to PWSCC and required both visual and volumetric examination of all nozzles on a prescribed frequency. IPEC meets the requirements of this order. Refer to the following letter regarding the IPEC response to EA-03-009. NL-04-026, "Answer to February 20, 2004 Revised NRC Order Regarding Interim Requirements for Reactor Pressure Vessel Heads Bulletin 2004-01 This bulletin requests that each PWR facility provide a description of their Alloy 82/182/600 materials used for pressurizer heater and steam space penetrations and inspection plans for future refueling outages. Neither IP2 nor IP3 pressurizers contain Alloy 82/182/600 components. Refer to the following letter regarding the IPEC response to bulletin 2004-01. NL-04-090, "Response to NRC Bulletin 2004-01 Regarding Inspection of Alloy 82/182/600 Materials Used In Pressurizer Penetrations and Steam Space Piping Connections"
25	AMP B.1.7-1 (Containment Leak Rate) The applicant indicates that this AMP is consistent with GALL AMP XI.S4, without exception or enhancement. GALL Vol.2, Rev. 1, AMP XI.S4, Scope of Program, states "Leakage testing for containment isolation valves (normally performed under Type C tests), if not included under this program, is included under LRT programs for systems containing the isolation valves." Is Entergy crediting 10 CFR Part 50, Appendix J,	The Containment Leak Rate Program includes Type A, Type B, and Type C tests of primary containment pressure-retaining components as described in 10 CFR Part 50, Appendix J. Thus, IP2 and IP3 are crediting 10 CFR Part 50, Appendix J, Type C containment isolation valve leak rate testing during the period of extended operation.

Item	Request	Response
	Type C containment isolation valve leak rate testing during the license renewal period?	
26	AMP B.1.8-1 (Containment Inservice) The intent of the staff in writing GALL Vol. 2 Chapter XI, was to enable an applicant to take credit for an existing mandated inspection program with minimal effort (i.e., simply identify and explain exceptions and enhancements). Entergy has identified AMP B.1.8 - Containment Inservice Inspection as being plant-specific. The staff reviewed LRA Appendix B.1.8 and concluded that the 10-element evaluation does not identify any differences from GALL AMPs XI.S1 and XI.S2. Entergy is requested to document an element-by-element comparison of AMP B.1.8 to GALL AMPs XI.S1 and XI.S2, identifying and explaining all exceptions and enhancements to the GALL AMPs.	Entergy performed an element-by-element comparison, available on-site, of IPEC AMP B.1.8, Containment Inservice Inspection, to NUREG-1801 AMPs XI.S1, ASME Section XI, Subsection IWE, and XI.S2, ASME Section XI, Subsection IWL. This will be added to the AMPER LRD-08 for AMP B.1.8. The comparison identifies and explains exceptions to the ten elements of the NUREG-1801 AMPs. IPEC AMP B.1.8, Containment Inservice Inspection does not require enhancement to satisfy the recommendations of NUREG-1801 AMPs XI.S1 and XI.S2. The Unit 2 and Unit 3 CLBs require that IPEC conduct ISI of containment in accordance with 10 CFR 50.55(a). This requirement will continue during the period of extended operation. For license renewal, the applicable code edition of ASME Section XI, subsections IWE and IWL will be determined in accordance with requirements of 10 CFR 50.55(a). Results of comparison to be incorporated into the LRA.
27	AMP B.1.8-2 (Containment Inservice) The IP 2 and 3 containments have a somewhat unique design feature: thermal insulation on the steel liner plate, at the lower elevations of the cylindrical containment wall. In both UFSARs, this insulation is credited with limiting the liner temperature increase to 80 degrees F during a design basis accident. Both UFSARs state that the insulation is removable, to permit periodic inspection of the containment liner plate. (1) Identify the AMP and describe the specific inspections performed, to ensure that this insulation will continue to perform its intended function. (2) Describe the plant-specific operating experience related to removal of this insulation and inspection of the containment liner plate normally covered by the insulation. How does the condition of the normally insulated liner plate surface compare to the condition of the normally uncovered liner plate surface? Has augmented inspection, per Category E-C, been necessary?	(1) As shown in LRA Table 3.5.2-1, line item "liner plate insulation jacket", there is no aging effect requiring management for liner plate thermal insulation, therefore there is no AMP. (2) IP2 and IP3 have approximately 20% of the liner inaccessible due to the insulation at the lower elevations of the containment. At the 46' Elevation, a caulking sealant, used as a moisture barrier, is installed at the junction of the bottom edges of the insulation panels and the floor to prevent moisture from reaching the steel liner. When performing a visual examination of the liner, the insulation covering portions of the containment liner is not removed. The IWE examination includes inspection of the moisture barrier to ensure that it has not degraded. IP2 and IP3 will remove insulation during the required IWE examinations if insulation removal is required to meet the requirements in Table 2500-1. During the IWE first interval for IP2, corrosion was discovered on the liner during the first period (April 2000) containment inservice inspection. The corrosion existed in the portion of the liner where it is abutted by the fill slab that covers the base mat liner. A number of inspections, investigations, and evaluations were performed to determine the acceptability of the liner to perform its design function. The inspection found several areas where the moisture barrier was missing or not properly bonded between the floor slab and insulation. The degradation of the moisture barrier raised a concern relative to the condition of the liner. In order to address these concerns, IP2 selected nine (9) panels of the liner insulation for removal to facilitate augmented inspection, per Category E-C. During the removal and re-installation of these insulation panels, the opening covers are re-sealed with the caulking sealant in order to re-establish the moisture barrier. When the insulation was removed, minor corrosion (light rust) was noted. Thickness readings were taken with no significant wall loss detected. As a result of three consecutive inspections of the nine (9) panel areas, the containment liner plate in these areas was found dry and the corrosion inactive, and the liner plate was well within the required containment liner thickness. In conclusion, the IP2 VC liner will perform its' intended function and is within acceptance limits for continued operation. This augmented exam was completed during the last IP2 Containment ISI Interval.
28	AMP B.1.8-3 (Containment Inservice) Identify all augmented inspections required by IWE or IWL that are being implemented during the current inspection intervals. For each case, describe the initial finding that necessitated augmented inspection.	Neither IP2 nor IP3 have any augmented inspections required by IWE or IWL during the current inspection intervals.
29	AMP B.1.8-4 (Containment Inservice) Entergy does not credit GALL AMP XI.S8 for license renewal. Confirm that Level I containment protective coatings are not credited for liner plate corrosion prevention/mitigation in the current	The liner plates of IP2 and IP3 containment are provided with appropriate protective coatings. However, the Level I containment protective coatings are not credited for liner plate corrosion prevention/mitigation in the current design bases for IP2 and IP3.

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	design bases for IP 2 and 3.	
30	AMP B.1.8-5 (Containment Inservice) TLAA 4.6-1 In its review of TLAA Section 4.6, the staff noted that in 1973 a significant permanent deformation of the IP Unit 2 liner plate occurred at the penetration for feedwater line #22. The operating experience element of AMP B.1.8 does not discuss this existing condition nor the results of periodic inspections conducted under the Containment ISI Program. (a) Describe in greater detail the event that resulted in the permanent liner plate deformation. When specifically did it occur? What was identified as the root cause? How was this corrected? (b) Discuss the history of ISI of the permanently deformed liner plate, from 1973 to the present.	(a) Describe in greater detail the event that resulted in the permanent liner plate deformation. Following a reactor trip from approximately 7% power, a break occurred in the feedwater line to Steam Generator No. 22 just inside containment near the feedwater line penetration. An area of the containment liner adjacent to the feedwater line break was slightly bulged, apparently as a result of steam and water impingement. The feedwater line incident report NL-74-A07, dated January 14, 1974, from William J. Cahill, Jr., Vice President Indian Point to John F. O'Leary, Director of Licensing Atomic Energy Commission will be available on site for staff review. When specifically did it occur? November 13, 1973 What was identified as the root cause? The bulging of the containment liner in the vicinity of the steam generator No. 22 feedwater line at the penetration was caused by the impingement of steam and water on the liner. How was this corrected? The containment building was pressurized to push the bulged liner back in place. The liner moved 5/8 of an inch during pressurization to 15 psig and no further during pressurization to 47 psig. This led to the conclusion that the liner made contact with the concrete after the 5/8 inch shift and that the extent of the deformation was not as great as originally suspected. Numerous modifications were made to prevent water hammers in feedwater lines and improve piping and liner ability to withstand such forces. These included adding an additional 18 feet of insulation above the pipe break area completely around the inside of containment (an additional 8 feet in the vicinity of the steam and feedwater lines), changing the piping layout to steam generator No. 22 inside containment, installing additional pipe supports, and installing "J Tubes" on the feedwater ring inside the steam generators to delay the draining of the feedwater rings which allowed a steam/water interface to develop. (b) General visual examinations were conducted under the Containment Inservice Inspection Program between June, 2004 and November 2004 for all accessible areas of the containment liner, including penetrations and airlocks, in accordance with Table IWE-2500-1, Category E-A, Item E1.11. Minor surface corrosion and/or coating deterioration were observed on the penetrations. This is general surface corrosion that has not resulted in any significant loss of material. The containment leak rate test at IP2 in 2006 was completed satisfactorily.
31	AMP B.1.9-1 (Diesel Fuel Monitoring) Provide a more detailed description of past and present fuel oil monitoring activities at the Indian Point site, including surveillance and maintenance procedures implemented to mitigate corrosion and verify the effectiveness of the Diesel Fuel Monitoring aging management program. Provide the frequency for the maintenance activities.	The Diesel Fuel Monitoring Program currently includes sampling activities and analysis on the following tanks in accordance with technical specifications on fuel oil purity and the applicable guidelines of ASTM Standards D1796 (water and sediment by centrifuge), D2276 (particulate gravimetrically), and D4057 (sampling). •EDG fuel oil storage tanks (21/22/23-FOST, EDG-31/32/33-FO-STNK) Properties of #2D Diesel fuel per ASTM D975, particulates per D2276, Tested 1/80 days •EDG fuel oil day tanks (21/22/23-FODT, EDG-31/32/33-FO-DTNK) Viscosity, Water and Sediment only (D1796) Tested 1/month •Gas turbine fuel oil storage tanks (GT2/3-FOT, GT1-FOT-11/12) Properties of #2D Diesel fuel per ASTM D975, particulates per D2276, Tested 1/80 days •Diesel fire pump fuel oil storage tank (DFPFOT) (IP2) Properties of #2D Diesel fuel per ASTM D975, particulates per D2276, Tested 1/184 days •Security diesel fuel oil day tank (SDDT) (IP2) Viscosity, Water and Sediment only (D1796) Tested 1/month •Appendix R fuel oil storage tank (ARDG-FO-ST) (IP3) Properties of #2D Diesel fuel per ASTM D975, particulates per D2276, Tested 1/184 days •Appendix R fuel oil day tank (ARDG-FO-DT) (IP3) Viscosity, Water and Sediment only (D1796) Tested 1/month •Diesel fire pump fuel oil storage tank (FP-T-3) (IP3) Properties of #2D Diesel fuel

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		per ASTM D975, particulates per D2276, Tested 1/184 days The specific fuel oil monitoring activities are accomplished in accordance with the technical specifications and procedure 0-CY-1810. The EDG fuel oil storage tanks, EDG fuel oil day tanks, GT1 gas turbine fuel oil storage tanks, GT2/3 gas turbine fuel oil storage tanks, diesel fire pump fuel oil storage tanks, security diesel fuel storage tank, and IP3 Appendix R fuel oil day tank, are periodically sampled, near the bottom, once per month to determine water content. Reference the following procedures which were provided on site for review: (Ref. Attachment 4, 0-CY-1500; Attachment 1, 0-CY-1810) (IP2 Ref. Section 4.3, 2-CY-1560) The EDG and GT2/3 fuel oil storage tanks are drained, cleaned and inspected every ten years to detect potential degradation and confirm the absence of aging effects. Reference the following procedures which were available on site for review: (IP2 Ref. Section 4, 2-GNR-009-ELC; GT2/3-FOT*001) (IP3 Ref. Section 4, GNR-024-ELC) Thickness measurements were performed once on the IP3 EDG fuel oil storage tanks (31 and 32) to verify that significant degradation was not occurring. The Above Ground Steel Tanks Program includes the use of NDE techniques (UT) for the GT2/3 fuel oil storage tank once every ten years during visual inspections. Reference the following procedures which were provided on site for review: (IP3 Ref. Section 4, GNR-024-ELC), (PM task GT2/3-FOT*001)
32	AMP B.1.9-2 (Diesel Fuel Monitoring) The LRA is silent on the use of tank coatings. Are the internal surfaces of any of the fuel oil storage tanks within the scope of license renewal coated or lined? If so, describe how the aging of the coating or lining is managed.	The only tanks known to have an internal coating are the security diesel fuel oil day tank (SDDT) and two EDG fuel oil storage tanks (EDG-31/32-FO-STNK). The coating in tanks is not credited to prevent aging effects that could result from the fuel oil environment. The EDG fuel oil storage tanks are inspected on a 10 year frequency in accordance with 3-GNR-024-ELC. Step 4.4.1.30 requires an inspection of the internal of the tank for any physical defects which would include defects in the coatings. The SDDT tank is nonsafety-related tank that is not inspected due to its small size (10 gallons). Degradation of the coating would be detected by sampling of the fuel oil in the tank for particulates. Any coating degradation will be evaluated under the corrective action program.
33	AMP B.1.9-3 (Diesel Fuel Monitoring) LRA AMP B.1.9 states that the program is being enhanced to include cleaning and inspection of the GT1 fuel oil storage tanks, EDG fuel oil day tanks, and SBO/Appendix R diesel generator fuel oil day tank once every ten years. Provide a more detailed description of past and present fuel oil monitoring activities related to these tanks.	The GT-1 tanks are monitored in accordance with technical specifications on fuel oil purity and the guidelines of ASTM Standards D1796 (water and sediment by centrifuge), D2276 (particulate gravimetrically), and D4057 (sampling). In addition the GT1 gas turbine fuel oil storage tanks, EDG fuel oil day tanks, and SBO/Appendix R diesel generator fuel oil day tank are periodically sampled, near the bottom, to determine water content. The frequencies and acceptance criteria are provided in the references below which were available on site for review. (Ref. Attachment 4, 0-CY-1500; Attachment 1, 0-CY-1810).
34	AMP B.1.9-4 (Diesel Fuel Monitoring) The LRA states that IPEC does not add biocides to diesel fuel oil storage tanks as recommended in GALL, to prevent biological breakdown of the diesel fuel. Rather, the existing processes for minimizing water contamination of the fuel and reviewing site and industry operating experience appear to be credited. While these processes may be effective in determining the existence of biological contamination, they do not appear to meet the intent of GALL for preventing and minimizing the accumulation of biological activity. Also, the LRA does not address an apparent exception to NUREG 1801, Element 7, regarding the addition of biocide to fuel oil when the presence of biological activity is confirmed. Please clarify.	At IPEC the evidence of microbiological activity, if any, is evaluated under the corrective action program. If the evaluation determines a need to use biocides based on additional sampling and monitoring, this will be handled in the corrective action program. However, the site does not immediately introduce biocides on the detection of microbiological activity based on ASTM Special Technical Publication 1005. The following is a summary of points from ASTM Special Technical Publication 1005, Distillate Fuel: Contamination, Storage and Handling. Copy of document provided on site for review. "The mere detection of viable microorganisms in hydrocarbon fuels or oils is not evidence of a significant microbial involvement. Distribution of the microorganisms is unlikely to be homogeneous, and obtaining a representative sample can be difficult or impossible. In contrast to this uncertainty (that microbes are homogeneously distributed) the appearance of corrosivity in stored petroleum products is good presumptive evidence that sulfate-reducing bacteria are at work." "As a first step in preventing the adverse effects of microbial growth in practical situations, water should be eliminated from storage and handling systems. As a last resort the use of a biocide may be necessary. The new problems that are introduced, as the result of using a biocide should be carefully considered."

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		IPEC does take exception to Element 2 in that biocides are not currently used at IPEC, However, this is not considered an exception to GALL in element 7 since biocides will be used if evaluation under the correction action program deems them necessary to correct the condition. Procedures 2-CY-1560 section 4.5 and 3-CY-2615 section 4.1 allow the addition of biocides for IP2 and IP3 if needed.
35	AMP B.1.9-5 (Diesel Fuel Monitoring) Describe how the quality of initial fuel oil purchases and deliveries is ensured.	Purchase specifications for fuel oil have specific technical requirements that the fuel be ASTM 2D fuel oil meeting the specifications of ASTM D975 in order to ensure it meets quality standards for delivery.
36	AMP B.1.9-6 (Diesel Fuel Monitoring) The LRA states that thickness measurements of storage tank bottom surfaces are performed to verify that significant degradation is not occurring. Provide the procedures used to perform this surveillance and describe the acceptance criteria and basis for minimum wall thickness. Also provide a technical basis for the specified 10 year surveillance frequencies.	The only fuel oil tanks with procedures or tasks requiring NDE of the tank bottom are the IP3 EDG storage tanks and the GT2/3 storage tank. These inspections are described in procedure GNR-024-GLC and PM task GT2/3-FOT*001 which are available on site for review. The minimum acceptable thickness for each tank bottom when inspected is based upon a component specific engineering evaluation. Wall thickness will be acceptable if greater than the minimum wall thickness for the specific component. A copy of PM task was provided for review. The basis for the 10 year wall thickness inspection frequency is to perform the inspections in conjunction with other 10 year inspections and cleanings which is consistent with the recommended frequency in Reg. Guide 1.137 and meets New York State regulations for fuel oil storage tanks. Past visual inspections of fuel oil storage tanks have not detected significant degradation that would lead to a need for an increased inspection frequency.
37	AMP B.1.9-7 (Diesel Fuel Monitoring) Provide the schedule for implementation of the enhancements to this AMP.	As specified in the IPEC commitment list for Commitment 7, the implementation schedule for the enhancements to this program are IP2: September 28, 2013 IP3: December 12, 2015
38	AMP B.1.11-1 (External Surfaces Monitoring) Give details of surfaces included in the external Surface Monitoring Program accessible only when the insulation is removed.	The surfaces included in the program are the external surfaces of carbon steel, stainless steel, copper alloy, cast iron, and aluminum components that are normally insulated. Surfaces that are insulated are inspected when the external surface is exposed, e.g., during maintenance. Routine maintenance occurs at such intervals that there is reasonable assurance that the effects of aging will be managed such that applicable components will perform their intended function during the period of extended operation.
39	AMP B.1.12-1 (Fatigue Monitoring) The LRA states in the Program Description: The program ensures the validity of analyses that explicitly analyzed a specified number of fatigue transients by assuring that the actual effective number of transients does not exceed the analyzed number of transients. (a) Please describe the method used to determine the actual effective number of transients. (b) Which component(s) will this methodology be applied to?	(a) IP2 and IP3: Site data is reviewed by a cognizant engineer to determine transients that have occurred since the last review. The engineer then updates the list of total transients to date. Transients reviewed include those listed in Table 4.3-1 (IP2) and 4.3-2(IP3) of the LRA and Table 4.1-8 of the UFSAR. Procedures 2-PT-2Y015, Thermal Cycle Monitoring Program and 3PT-M051, Plant Operation Information was available for review on-site and provide further details. As described in the enhancement to the Fatigue Monitoring Program, IP3 will complete a review of existing fatigue analyses of record and enhance the fatigue monitoring program to include additional transient cycles similar to what has been done for IP2. This enhancement to the IP3 identification and tracking of transients is identified in Commitment 6. (b) Determination of actual numbers of transients is independent of specific components. The method is applied to transients. Different components are affected by different transients. The basis for the IP2 design cycles is described in WCAP-12191, Revision 3, "Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Final Report for Indian Point 2". WCAP-12191 was available for review on-site.
40	AMP B.1.12-2 (Fatigue Monitoring) The LRA states in the Exception Section that "The IPEC program updates fatigue usage calculations when the number of actual cycles approach the analyzed number of cycles." What are the action or alarm limits that will trigger	IP2: Alert cycles are defined as the number of cycles which may accumulate in two monitoring periods. If the number of analyzed cycles is exceeded using alert cycles, a condition report is generated to ensure that corrective actions are taken prior to exceeding the analyzed number of cycles. The number of alert cycles is calculated by taking the cycles accumulated during the period, multiplying them by 2, and adding them to the total accumulated cycles to date. If this projection remains below the total number of analyzed cycles, no further action is required.

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	the corrective action.	IP3: The current fatigue monitoring program does not have action or alarm limits. The cognizant engineer and the reviewing supervisors determine if a condition report is required. Plant operation is not allowed if the analyzed number of a particular transient is exceeded unless appropriate engineering evaluation under the corrective action program has determined it acceptable. This item has been closed to question #119.
41	AMP B.1.12-3 (Fatigue Monitoring) Under Enhancement Section: For IP3, the applicant proposes to "revise appropriate procedures to include all the transients identified." (a) Please list all applicable transients. (b) Why does this enhancement not apply to IP2?	(a) LRA Table 4.3-2 reflects the transients monitored by the IP3 fatigue monitoring program. IP3 has not expanded the program beyond UFSAR Table 4.1-8. IP3 will complete a review of existing fatigue analyses of record and enhance the fatigue monitoring program to include additional transient cycles similar to what has been done for IP2. This enhancement to the IP3 identification and tracking of transients is identified in Commitment 6. (b) IP2 has performed a detailed review of required transients as documented in WCAP-12191, Revision 3, "Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Final Report for Indian Point 2". WCAP-12191 is available for review on-site.
42	AMP B.1.12-4 (Fatigue Monitoring) The LRA states in the Operating Experience that the Fatigue Monitoring Program includes re evaluation of usage factors as appropriate. (a) What factors/conditions would warrant a re-evaluation. (b) Under what circumstances that IP2 charging nozzles were re-evaluated? Please describe the re-evaluations process for IP2 charging nozzles.	(a) Cumulative usage factors (CUF) are re-evaluated when the actual number of cycles approaches the design limit as shown in UFSAR Tables 4.1-8 for IP2 and IP3. Refer to the response to Audit Question AMP B.1.12-2. (b) The original IP2 design did not include a fatigue analysis for charging nozzles. Westinghouse noted the transient in letter IPP-90-752 dated September 1990. The IP2 charging nozzle transient cycle history was updated along with other analyzed transients in the development of WCAP-12191, Revision 3, "Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Final Report for Indian Point 2".
43	AMP B.1.15-1 (Flow-Accelerated Corrosion) The LRA states that the incidents of wall thinning were detected in the vent chamber drain and high pressure turbine drain components during 3R13 in March 2005 and in a steam trap pipe during 2R17 in May 2006. These incidents resulted in replacements of the affected components during the respective outages. Describe if the piping and the affected components were included in the FAC program prior to these inspections and if the affected components were replaced with the like for like materials or with a FAC resistant material such as chrome-moly. Also substantiate the response with actual thickness data, i.e., the nominal thickness, minimum acceptable thickness and the measured thickness at these affected locations.	The piping and affected components were included in the FAC program prior to these inspections. As the wall thinning of these components was discovered during the outage, they were replaced with like for like materials. Subsequent to these outages, the Wet Steam Pipe Replacement Project has and will replace piping found to be worn by past FAC inspections with FAC resistant materials. The High Pressure Turbine Drain piping downstream of the control valves was replaced with chrome moly during 3R14. The Vent Chamber Drain piping is to be replaced with chrome moly piping. The replacement is to be performed in three phases. Phase 1 included the "A" train and was completed during 3R14. Phase 2, to be performed during 3R15 will include the "B" Train, and Phase 3 to be performed during 3R16 will include the common "A" and "B" Train piping. Actual thickness data of vent chamber drain, high pressure turbine drain and steam trap components are provided below. Unit 3 Vent chamber drain piping - 3" diameter, schedule 40 Nominal wall thickness 0.216" Minimum acceptable thickness.0.123" Minimum thickness required for 2 more years of service after 3R13 0.135" Minimum measured thickness 0.052" High pressure turbine drain piping – 2" diameter, schedule 80 Nominal wall thickness 0.218" Minimum acceptable thickness is 0.083" Minimum thickness required for 2 more years of service after 3R13 0.116" Minimum measured thickness is 0.085". High pressure turbine drain piping – ¾" diameter, schedule 80 Nominal wall thickness 0.154" Minimum acceptable thickness 0.046" Minimum thickness required for 2 more years of service after 3R13 0.059" Minimum measured thickness 0.059" Unit 2

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		Steam trap piping – 1" diameter, schedule 80 Nominal wall thickness 0.179" Minimum acceptable thickness 0.054" Minimum thickness required for 2 more years of service after 2R17 0.072" Minimum measured thickness 0.063"
44	AMP B.1.15-2 (Flow-Accelerated Corrosion) The LRA states that operating experience for IP2 and IP3 was accounted for in the most recent updates of the respective CHECWORKS FAC models. The LRA further states that the CHECWORKS models were updated using the inspection data from the outage inspections and the FAC wear rate changes due to the recent power uprates. Provide a time line when these models were updated and inspection data from which outages was utilized in the updates. Has IP ever experienced situations in which the model predicted wear rates may have been lower than the actual wear rates measured during FAC inspections? If yes, describe how were these nonconservative wear rate predictions handled and what has been done to correct the model?	Timeline for CHECWORKS update – Unit 2 CHECWORKS Model update completed 3/23/2005 incorporating the wear rate changes due to the power uprate. CHECWORKS Model update completed 9/12/2006 incorporating 2R17 inspection data. Unit 3 CHECWORKS Model update completed 3/23/2005 incorporating the wear rate changes due to the power uprate. CHECWORKS Model update completed 10/25/2005 incorporating 3R13 inspection data. CHECWORKS Predicted wear rates – Indian Point has adopted EPRI recommendations and modeled plant piping using realistic operating conditions. Therefore, there are instances where the model predicted wear rate is less than the actual wear rates measured during FAC inspections. This results in a Pass 2 analysis Line Correction Factor (LCF) greater than 1.0, indicating the CHECWORKS algorithm is under-predicting the wear rates. In cases where the wear rate is higher than predicted and remaining service hours are low, these components are selected for inspection, thereby targeting the "worst" components first and expanding the inspection scope to other components that are also likely worn. The increase in inspections provides assurance the components are suitable for continued service, and additional inspection data as input to the model. Once the components have been inspected, a trended wear rate approach (from section 4.7 of EPRI NSAC 202L) is used to schedule the next time to inspect the components, with safety factors for conservatism. The CHECWORKS model is corrected every outage with the latest chemistry, operating, and inspection data. Through the Pass 2 Wear Rate Analysis process in CHECWORKS, predicted wear rates are adjusted to coincide with measured wear rates. In the case where the model predicted wear rate is less than the actual wear rate, the predicted wear rates are increased (multiplied by the LCF) to match the inspection data. Over time, this approach aligns CHECWORKS predictions to actual conditions in the plant.
45	AMP B.1.15-3 (Flow-Accelerated Corrosion) Provide a few examples of modifications and/or improvements to the FAC program at Indian Point in the past five years. What were the specific reasons (e.g., lessons learned, plant operating experience, industry experience or other (define)) for those changes and how have the changes made the FAC program more effective with respect to the management of aging?	1. Update of CHECWORKS version from 1.0G to SFA CHECWORKS FAC Version 1.0 was released by EPRI in 1993. In 2000, in recognition of the fact that CHECWORKS would not function under future Windows operating systems, EPRI began development of the successor code, CHECWORKS SFA 2.0 (and later CHECWORKS SFA 2.1 and 2). The reason for the conversion is twofold. The first was to stay current with industry trends. With the release of CHECWORKS SFA, EPRI will discontinue support of the CHECWORKS 1.0 software. To benefit from any future changes or improvements to the CHECWORKS software, the database must be compatible with CHECWORKS SFA. The second intention of the conversion was to improve the accessibility to the CHECWORKS database. Conversion to CHECWORKS SFA creates a model with the ability to import and export data (not possible in version 1.0), enabling us to more accurately and efficiently compile program information such as outage inspection scopes. 2. Implementation of FAC Manager software Use of FAC Manager software was implemented at IPEC. Industry experience using this software has been positive. The software allows us to efficiently manage FAC related activities. For example, FAC Manager performs all the non safety-related wall thinning calculations (100+ calculations per outage) using the Entergy Engineering Standard "Pipe Wall Thinning Structural Evaluation" ENN-CS-S-008.

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		This software decreases the probability of calculation error associated with manual calculations resulting in less errors and omissions. Other benefits include: It provides a consistent approach at all facilities benefiting shared resource personnel. All FAC related data is consolidated in one place, saving time and minimizing errors due to referencing several data sources. Multi-user / site capability allows analysis from other sites, utilizing resources and expertise from across the fleet. 3. Updating CHECWORKS Model to include power uprate Power uprate changed feedwater and steam flow rates, and temperatures, which in turn changed local chemistry values. All of these factors affect wear rates due to FAC. The pre-uprate CHECWORKS model did not address the changes resulting from the Appendix K and stretch power uprate. The update of the CHECWORKS model reflects all plant power level changes (the original power level, Appendix K uprate and stretch power Uprate). Historical (pre-uprate and Appendix K uprate) operating conditions remain within the model, associated with the applicable operating cycles. This ensures that the model's predictions of total current and future wear will be as accurate as possible because the predictions will be based on both historical and current operating conditions. 4. Development of fleet FAC procedure EN-DC-315 To support the Entergy standardization effort, a fleet-wide FAC procedure was developed to standardize the FAC program at all the Entergy Nuclear sites. A common corporate procedure provides a consistent approach to managing FAC. This enables more efficient use of shared resources, and facilitates the effective use of knowledge/expertise and operating experience across the fleet.
46	AMP B.1.15-4 (Flow-Accelerated Corrosion) If the thickness measurements during FAC inspection indicate degradation or wall thinning beyond the predicted minimum wall thickness, how would the sample size be adjusted under Indian Point's FAC Program to address the detected degradation? Include actual inspection data and examples to substantiate the response.	[1] If a component is discovered that has a current or projected wall thickness less than the minimum acceptable wall thickness (Taccpt), then additional inspections of identical or similar piping components in a parallel or alternate train is performed to bound the extent of thinning. [2] When inspections of components detect significant wall thinning, the sample size for that line is increased to include the following: (a) Components within two diameters downstream of the component displaying significant wear or within two diameters upstream if the component is an expander or expanding elbow. (b) A minimum of the next two most susceptible components from the relative wear ranking in the same train as the piping component displaying significant wall thinning. (c) Corresponding components in each other train of a multi-train line with a configuration similar to that of the piping component displaying significant wall thinning. Vent Chamber Drain (VCD) pipe thinning during 3R13 3R13 inspection of a VCD elbow immediately downstream of MSR-31A PCV-7008 found wall thinning less than the minimum acceptable wall thickness, requiring replacement of the elbow. Based on the results of this exam, a sample expansion was performed to determine the extent of condition for this pipe thinning. The expansion included corresponding components on the other moisture separator reheaters with a configuration similar to that of the elbow displaying the thinning. Four additional inspections were performed. These inspections also found wall thinning less than the minimum acceptable wall thickness, requiring replacement of these components. The sample expansion was continued until no additional components were detected with significant wear. Four additional inspections were performed downstream of the worn elbows. The results of this expansion did not find significant wear and the sample expansion was terminated. The vent chamber drain lines on Unit 2 were replaced with FAC-resistant materials, and were not considered in this sample expansion. Reheater Drain pipe thinning during 3R14 A leak in the reheater drain system was detected during cycle 14. A review of both Unit 2 and Unit 3 FAC programs was performed to determine if similar locations to this leak have been inspected for wall thinning and determine if additional inspections were required. A review of the Unit 2 FAC inspection history found that all similar locations had been recently inspected or replaced. No additional inspections were recommended.

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		A review of the Unit 3 FAC inspection history found some similar locations that did not have recent inspections and were recommended for inspection. A total of 9 inspections were added on the A and B trains at locations similar to the leak. As a result of these inspections, two elbows were found to have wall thinning and were replaced during 3R14. Review of the sample expansion developed for the initial leak determined that the wall thinning was bounded by this expansion. All similar locations have been identified and scheduled for inspection during 3R14. Inspection of the remaining 7 components found them acceptable for continued service, and will continue to be monitored in the FAC Program.
47	AMP B.1.15-5 (Flow-Accelerated Corrosion) How is the industry experience utilized in the FAC Program at Indian Point? How does IP gets feedback from other plants? Are there any unique differences between the FAC Programs of IP2 and IP3? If wall thinning or degradation is observed during FAC inspection of one unit, are the corresponding components on the other unit inspected for similar degradations?	Industry experience is reviewed in accordance with the corporate procedure EN-OE-100 Operating Experience Program and is implemented in conjunction with the corrective action program. Details on the review and actions to be taken are provided in this procedure. A site OE coordinator screens incoming operating experience for site applicability. This includes operating experience within the Entergy corporation and the industry. In addition, other utilities participate in QA audits of programs where they provide their unique experience. Industry experience is evaluated, and if applicable to IPEC is incorporated into the FAC inspection scope. Feedback from other plants is obtained from attendance at CHECWORKS users group (CHUG) meetings where industry OE is exchanged during the formal presentations as well as an information exchange session where each utility describes issues encountered since the last meeting. Another source of OE is FACnet. It is a communications tool used by FAC personnel to ask questions, share ideas, and exchange information via email. The only previous differences between the Unit 2 and Unit 3 FAC Programs were dealing with how the data was stored and how specific component evaluations were performed. With the implementation of the corporate FAC procedure and the use of FAC Manager, the Unit 2 and Unit 3 FAC programs are now very similar. When thinning or degradation is observed during FAC inspection of one unit, the corresponding components on the other unit are evaluated for similar degradation. Examples are provided in the response to AMP B.1.15 Question # 46, where the extent of condition review evaluates the other unit for similar degradations
48	AMP B.1.15-6 (Flow-Accelerated Corrosion) The LRA states that the FAC Program for IP2 was audited in 2004 and that the audit team determined that the program was effective and in compliance with ASME code, EPRI standards, and INPO guidelines and NRC regulations. (a) Which organization performed this audit and what was the purpose of this audit? Was a similar audit performed on IP3 FAC Program? (b) Explain which specific documents of the stated organizations were used in the audit to establish program compliance. (c) Which specific elements of the Indian Point FAC Program and what specific documentation pertaining to the program was reviewed by the audit team to establish that the program was effective?	(a) This was an internal QA department audit with assistance from an outside utility and the purpose was to confirm that several IPEC Unit 2 programs including FAC were in compliance with the requirements of the NRC Regulations, Codes, Industry Standards, IPEC Unit 2 Technical Specifications, Final Safety Analysis Reports and commitments. A similar audit was recently performed for Unit 3 in the spring of 2007 and documented in audit report QA-08-2007-IP-1. This audit determined that the program was satisfactory with no findings. There have also been QA surveillances performed of the IP3 and IP2 programs in 2005 and 2006. (b) QA audits are performed in accordance with corporate nuclear management manual procedure EN-QV-109 Audit Process. The following specific documents of the organizations stated in the question were reviewed as part of the audit: NRC Generic Letters 89-08 & 90-05, NUREG-1344, ANSI B31.1, EPRI Report TR-10611, NSAC 202L-R2, INPO SOER's 87-3 & 82-11. (c) The following features of the FAC program were reviewed: procedures, FAC inspections, industry experience, wall thinning analysis and calculations, and corporate and IPEC commitments. Though this inspection was not an inspection of the FAC program elements described in NUREG-1801, it did review portions of the program that encompass elements of B.1.15. These elements would be Scope, Preventive Actions, Parameters Monitored, Detection of Aging Effects, Monitoring and Trending, Acceptance Criteria, and Operating Experience. Examples of documents reviewed include ENN-DC-315 rev. 0, ENN-NDE-9.05, EPRI Technical Report NSAC-202L-R2, IP-CALC-04-01727 and IP-CALC-04-01620, and IP-CALC-04-01713, Revision 0
49	AMP B.1.15-7 (Flow-Accelerated Corrosion) The LRA includes operating experience items which pertain to inspections during 3R13 and 2R17 outages for IP3 and IP2 respectively. Both items are recent (March 2005 and May 2006 respectively) items. Provide more examples of inspection results to demonstrate that the FAC	Identification of degradation and corrective action prior to loss of intended function provide assurance that the FAC Program is effective for managing aging effects due to flow accelerated corrosion. Corrective actions are addressed by the wet steam replacement project. This project is a multi-year task to replace FAC susceptible piping with FAC resistant material. Replacement materials include stainless steel, chrome-moly and carbon steel pipe with a stainless steel liner. The following are more examples of inspection results to demonstrate that the FAC

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	program at Indian Point is effective in managing the aging effect.	program is effective in managing the effects of aging. Wall thinning was found on the LP extraction steam lines to the Unit 2 22 feedwater heaters that are located inside the condenser neck. As part of the wet steam pipe replacement project, these lines are being replaced with FAC-resistant chrome moly material. The 22C feedwater heater extraction steam lines were replaced during 2R17 (2006) and the 22A and 22B feedwater heaters extraction steam lines are to be replaced during 2R18 with chrome moly material. Inspections performed for Unit 3 32 feedwater heater extraction line found these components acceptable for continued service and will not require replacement. Wall thinning was found on two 35 extraction steam elbows during 3R14 FAC inspections. As part of the wet steam pipe replacement project, these lines are being replaced with FAC-resistant chrome moly material during 3R15. The 25 extraction steam line for Unit 2 was replaced entirely with stainless steel and chrome moly material. Wall thinning was found on the steam lines from the preseparators to the 35 extraction steam header at Unit 3 during 3R12 FAC inspections. As part of the wet steam pipe replacement project these lines were replaced with carbon steel piping with a stainless steel cladding during 3R13 (2005). The 25 extraction steam line for Unit 2 was replaced entirely with stainless steel and chrome moly material. Additional pipe replacements by the Wet Steam Pipe Replacement Project include: 3R14, 2007 Due to wear found in FAC inspections, approximately 700' of carbon steel Vent Chamber Drain piping was replaced with FAC resistant chrome moly piping. In addition, the carbon steel discharge piping from the High Pressure Turbine Drain Main Steam flow control valves (9 lines totaling approximately 50 feet of pipe) to the condenser were replaced due to wall thinning observed during FAC examinations. 2R16, 2004 Due to wear found in FAC inspections, approximately 200' of carbon steel Vent Chamber Drain piping was replaced with FAC resistant chrome moly piping. Also replaced was approximately 10' of carbon steel MSR drain piping downstream of LCV-1105A to the 26 FWHs with FAC resistant chrome moly. 3R12, 2003 Due to wear found in FAC inspections, the carbon steel North to South Main Steam Trap header was replaced with FAC resistant chrome moly piping; the 33 Feedwater Heater Operating vent carbon steel piping was replaced with FAC resistant chrome moly. 2R15, 2002 Due to wear found in FAC inspections, approximately 150' of carbon steel extraction steam piping to FWH23A was replaced with FAC resistant chrome moly, and approximately 200' of carbon steel Feedwater Heater 23 A, B and C operating vent piping was replaced with FAC resistant chrome moly. 3R11, 2001 Due to wear found in FAC inspections, approximately 40' of carbon steel extraction steam piping to the 35A and 35B FWH was replaced with FAC resistant chrome moly piping, and the carbon steel 36 FWH operating vents were replaced with FAC resistant chrome moly pipe. In addition 9 extraction steam traps carbon steel piping was replaced with FAC resistant chrome moly piping. 2R14, 2000 Due to wear found in FAC inspections, approximately 1700' of carbon steel Vent Chamber Drain piping was replaced with FAC resistant stainless steel, and approximately 115' of carbon steel 25 FWH extraction steam piping was replaced with FAC resistant stainless steel.
50	AMP B.1.16-1 (Flux Thimble Tube Inspection) LRA AMP B.1.16, "Program Description" states: " An NDE methodology, such as eddy current testing (ECT), or other similar inspection method is used to monitor for wear of the flux thimble tubes. This program implements the recommendations of NRC Bulletin 88 09, Thimble Tube Thinning in Westinghouse Reactors."	Consistent with the program description described in GALL, other applicant-justified and NRC-accepted inspection methods may be used. However, only eddy current testing is used to monitor thinning of flux thimble tubes at IP2 and IP3. The program description in LRA Sections A.2.1.15, A.3.1.15, and B.1.16 will be revised to state that eddy current testing is the NDE method used by the Flux Thimble Tube Inspection Program. The phrase "or similar inspection method" will be removed. Clarification to be incorporated into the LRA.

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	Discuss what other similar inspection method is used for monitoring the wear of flux thimble tubes for IP2 and IP3. How does this method compare with the ECT, as recommended in GALL?	
51	AMP B.1.16-2 (Flux Thimble Tube Inspection) LRA AMP B.1.6 includes three enhancements to be implemented prior to the period of extended operation for GALL consistency in program elements "Monitoring and Trending," "Acceptance Criteria," and "Corrective Actions." a.GALL "Monitoring and Trending" recommends: " The wall thickness measurements will be trended and wear rates will be calculated. Examination frequency will be based upon wear predictions that have been technically justified as providing conservative estimates of flux thimble tube wear. The interval between inspections will be established such that no flux thimble tube is predicted to incur wear that exceeds the established acceptance criteria before the next inspection. The examination frequency may be adjusted based on plant specific wear projections. Re baselining of the examination frequency should be justified using plant specific wear rate data unless prior plant specific NRC acceptance for the re baselining was received. If design changes are made to use more wear resistant thimble tube materials (e.g., chrome plated stainless steel) sufficient inspections will be conducted at an adequate inspection frequency, as described above, for the new materials." Discuss how the stated enhancement in the LRA satisfies the GALL for both IP2 and IP3. b. GALL "Accptance Criteria" recommends: " Appropriate acceptance criteria such as percent through wall wear will be established. The acceptance criteria will be technically justified to provide an adequate margin of safety to ensure that the integrity of the reactor coolant system pressure boundary is maintained. The acceptance criteria will include allowances for factors such as instrument uncertainty, uncertainties in wear scar geometry, and other potential inaccuracies, as applicable, to the inspection methodology chosen for use in the program. Acceptance criteria different from those previously documented in NRC acceptance letters for the applicant=s response to Bulletin 88 09 and amendments thereto should be justified." Discuss how the stated enhancement in the LRA satisfies the GALL for both IP2 and IP3. c. GALL "Corrective Actions" recommends: "Flux thimble tube wall thickness which do not meet the established acceptance criteria must be isolated, capped, plugged, withdrawn, replaced, or otherwise removed from service in a manner that ensures the integrity of the reactor coolant system pressure boundary is maintained. Analyses may allow repositioning of flux thimble tubes that are approaching the acceptance criteria limit. Repositioning of a tube exposes a different portion of the tube to the discontinuity that is causing the wear." Discuss how the stated enhancement in the LRA satisfies the GALL for both IP2 and IP3.	a. For IP2, the measurements from the last performance will be trended with the next scheduled wear rate measurement. While IP2 compares measured values in practice, the enhancement to Element 5 will formalize the process. For IP3, wear measurements are trended per Attachment 1, Section 6.0 of procedure THI-002-RVI where each tube inspection is recorded on datasheets and a permanent strip chart recording is made at the time of the inspection. Inspection results are recorded on a table in listed in THI-002-RVI. Wear rates and examination frequencies are calculated per RE-ICI-910625 which states that 80% wear would occur during cycle 24 for IP2. Wear rates and examination frequencies are calculated per IP-CALC-07-0038 which requires an eddy current inspection prior to 3R16 for IP3. Changing the baseline of the exam frequency has not occurred and the flux thimble tube design has not changed. Therefore, existing activities are consistent with the Flux Thimble Tube Monitoring Program attribute "Monitoring and Trending" with the enhancement to better formalize the process. b. IP2 and IP3 have established acceptance criterion of 80% through wall (thimble tube wall thickness is not less than 20% of initial wall thickness). Tubes with 80% through wall wear shall be replaced or isolated. Thimble tubes with wear exceeding 40% through wall but projected to remain under 80% by the next inspection may be repositioned after engineering evaluation. Thimble tubes with wear projected to exceed 80% by the next inspection will be repositioned, replaced, or isolated. This is conservatively based on WCAP-12866 recommendations which include potential inaccuracies. IPEC responses in April 1989 to Bulletin 88-09 cited acceptance criteria of 50% for IP2 and 60% for IP3. As recommended by the Bulletin, the Westinghouse Owners Group completed WCAP 12866 in 1991 which determined that a thimble can safely remain in service with up to 80% (includes conservatism) through wall loss. The results of the WCAP were adopted by IPEC in 1991. As described above, existing activities are consistent with the Flux Thimble Tube Monitoring attribute "Acceptance Criteria". The enhancement is intended to formalize these activities. c. Flux thimble tubes are isolated, capped, plugged, withdrawn, repositioned, or replaced when wall thickness is less than the minimum required. IP2: During the Spring 2006 IP2 outage, all flux thimble tubes were repositioned by approximately two inches as part of a seal table modification. Nine flux thimble tubes have been capped. IP3: Two flux thimbles have been capped as recommended by calculation IP-CALC-07-0038. These existing activities are consistent with the Flux Thimble Tube Monitoring Program attribute "Corrective Actions". The enhancement is intended to formalize these activities.

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52	AMP B.1.17-1 (Heat Exchanger Monitoring) The staff compared the enhancements to the Scope of Program with the specific AMR line items in LRA Sections 3.2 and 3.3 that credit AMP B.1.17 - Heat Exchanger Monitoring. A total of 14 AMR line item entries were located, all identified only as "Heat Exchanger - Tubes". These occurred under the following systems: Table 3.2.2-1-IP2 RHR (1 line item) Table 3.2.2-1-IP3 RHR (1 line item) Table 3.2.2-4-IP2 Safety Injection (1 line item) Table 3.2.2-4-IP3 Safety Injection (1 line item) Table 3.3.2-2-IP3 Service Water (1 line item) Table 3.3.2-3-IP2 Component Cooling Water (2 line items) Table 3.3.2-3-IP3 Component Cooling Water (2 line items) Table 3.3.2-6-IP2 Chemical & Volume Control (2 line items) Table 3.3.2-6-IP3 Chemical & Volume Control (2 line items) Table 3.3.2-16-IP2 SBO/App. R Diesel Generator (1 line item) The staff could not correlate the scope of program, including the enhancements, with the AMR table entries; and requests the following clarifications: (a) Identify the specific component inspections currently included in the existing program that are credited for license renewal. (b) Correlate the 14 AMR table entries identified above with the specific component inspections included in the enhanced program.	(a) This program is only credited to manage the aging effect of loss of material due to wear. The existing site eddy current heat exchanger inspection program includes safety-related and nonsafety-related heat exchangers. Eddy current inspections of Generic Letter 89-13 safety-related heat exchangers cooled by service water are included as part of the Service Water Integrity Program. The existing heat exchanger eddy current inspections on IP2 and IP3 are detailed in Appendix 1 and 2 of procedure IP3-RPT-UNSPEC-03499. The only heat exchangers currently included in the existing program are the IP3 instrument air heat exchangers SWN CLC 31/32 HTX that were inadvertently listed as needing to be added to the program as part of the enhancement. The existing program will be continued into the period of extended operation with enhancements. (b) Table 3.2.2-1-IP2 RHR / RHR heat exchangers (IP2 – 21/22RRHX) Table 3.2.2-1-IP3 RHR / RHR heat exchangers (IP3 - ACAHRS1/2) Table 3.2.2-4-IP2 Safety Injection / safety injection pump lube oil heat exchangers (IP2 - CCW-HTEX-WCLR-1009/1010/1011) Table 3.2.2-4-IP3 Safety Injection / safety injection pump lube oil heat exchangers (IP3 - SISP31/32/33 OC HTX), Table 3.3.2-2-IP3 Service Water /The line item in Table 3.3.2.2 IP3 Service Water refers to the IP3 instrument air heat exchangers SWN CLC 31/32 HTX. The inclusion of this heat exchanger as part of the enhancement is an error since these heat exchangers are in the existing eddy current inspection program. Table 3.3.2-3-IP2 Component Cooling Water / spent fuel pit heat exchangers (21SFPHX), secondary system steam generator sample coolers (21/22/23/24 SGSC), waste gas compressor heat exchangers (21/22 WGCSWC) Table 3.3.2-3-IP3 Component Cooling Water / spent fuel pit heat exchangers (ACAHSF1), secondary system steam generator sample coolers (SGBDS-31/32/32/34HX), waste gas compressor heat exchangers (WD-WGC-31/32HTX) Table 3.3.2-6-IP2 Chemical & Volume Control / non-regenerative heat exchangers (IP2 - 21NRHX), charging pump seal water heat exchangers (IP2 - 21SWHX), charging pump fluid drive coolers (IP2 – 21/22/23CHPFCA), charging pump crankcase oil cooler (IP2 - 21/22/23CHPFCB) Table 3.3.2-6-IP3 Chemical & Volume Control / non-regenerative heat exchangers (IP3 – CSAHNRT), charging pump seal water heat exchangers (IP3 - CSAHSW1), charging pump fluid drive coolers (IP3 - CHRG PP31/32/33 CASING HTX), charging pump crankcase oil cooler (IP3 - CHRG PP31/32/33 CRANK HTX) Table 3.3.2-16-IP2 SBO/App. R Diesel Generator / SBO/Appendix R diesel jacket water heat exchanger (ARDG-JWHX) Information to be incorporated into the LRA. The charging pump crankcase oil coolers were inadvertently omitted from the scope of heat exchangers to be included in the program and the IP3 instrument air heat exchangers SWN CLC 31/32 HTX are already included in the existing program and should not be part of the enhancement
53	AMP B.1.17-2 (Heat Exchanger Monitoring) The staff noted that all AMR table entries identify " Loss of Material - Wear" as the aging effect being managed. Is this wear induced by flow through and/or over the heat exchanger tubes? Does the wear result from abrasive fluid at high velocity or from flow-induced vibration of the tubes?	The wear that is identified by this aging effect is wear (fretting) on the outside of the tubes due to contact between the tubes and the tube support plates. It is not expected that this will occur but is conservatively identified as an aging effect requiring management. The wear could be caused by vibration of the tube as a result of high flows or excessive clearance between the tube and tube support plate. Wear resulting from abrasive fluid at high velocity is not expected in the heat exchangers included in this program due to the controlled water chemistry of the process fluids on the shell and tube sides.
54	AMP B.1.17-3 (Heat Exchanger Monitoring) Under "Parameters Monitored or Inspected", an " enhancement" to the existing program is to specify visual inspection where non-destructive examination, such as eddy current testing, is not possible. In the existing program, what is currently	All of the heat exchangers in the existing eddy current inspection program are large enough such that eddy current inspection can be performed. Visual inspection of the ID of heat exchanger tubes in the existing program is not routinely performed. Some of the new heat exchangers added by the enhancement are small enough such that eddy current inspection may not be possible necessitating visual inspection.

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	done if eddy current testing is not possible?	
55	AMP B.1.17-4 (Heat Exchanger Monitoring) Describe the details of the visual inspection techniques to be employed. Does this include remote visual inspection of the inside of the tubes? What specific acceptance criteria are applied to visual inspection? Compare this to the acceptance criteria applied to eddy current testing.	Depending on the size of the heat exchanger, tube configuration, and tube size, a remote visual inspection of the tubes may be required if eddy current examination of the tubes is impractical. Remote visual inspection may be performed by means of a fiberscope inserted through the tubes, or on the tube exterior from the shell side. As specified in the enhancement for the acceptance criteria attribute, appropriate procedures will be revised to establish acceptance criteria for heat exchangers visually inspected to include no unacceptable signs of degradation. This is identified as commitment #10. The eddy current tests have a minimum acceptable tube wall thickness acceptance criterion, which is determined by engineering evaluation on a heat exchanger-specific basis. -
56	AMP B.1.17-5 (Heat Exchanger Monitoring) Do any of the heat exchangers included in the scope of this AMP come under the jurisdiction of ASME Code Section III and Section XI? If yes, identify the specific heat exchangers and discuss how the Section XI requirements for inspection are satisfied by this AMP.	This AMP manages the aging effect of loss of material due to wear for the tubes in the heat exchangers listed under the enhancement for the scope of the program. The tubes in the other heat exchangers currently in this program are eddy current tested to detect loss of material. Some heat exchangers are classified as ISI Class 1, 2, and 3 and are subject to the requirements of ASME Section XI inservice inspection and repair / replacement requirements associated with the pressure boundary. Repairs or modifications to heat exchangers will comply with the design code(s) of record (ASME Section III and/or ASME Section VIII, as applicable). The heat exchanger monitoring program does not implement any of these repair/ replacement or inspection activities.
57	AMP B.1.18-1 (Inservice Inspection) LRA AMP B.1.18, Program Description states: The Inservice Inspection (ISI) Program is an existing program that encompasses ASME Section XI, Subsections IWA, IWB, IWC, IWD and IWF requirements at GALL AMP XI.M1 imposes requirements for Subsections IWB, IWC, and IWD for Class 1, 2, and 3 pressure retaining components and their integral attachments. Subsection IWA describes general requirements associated with Subsections IWB, IWC, and IWD. GALL AMP XI.S3 covers Inservice inspection of Class 1, 2, 3 and MC component supports for ASME piping and components addressed in Section XI, Subsection IWF. The staff notes that the 10 element evaluation for the Subsection IWF inspection is not explicitly addressed in LRA AMP B.1.18. (a) Provide a detailed 10 element evaluation of the Subsection IWF inspection for Class 1, 2, 3 and MC component supports and discuss any exceptions or enhancements when assessed against the recommendations in GALL AMP XI.S3, AASME Section XI, Subsection IWF. Specifically, discuss the inspection methods, their frequencies, sampling methods for each class of supports, acceptance criteria, and operating experience findings and their corrective measures. (b) The attributes of AMP B.1.18 and GALL AMP XI. M1 are mostly identical and consistent, except AMP B.1.18 also includes the GALL AMP XI.S3 for supports. Explain why Entergy categorizes AMP B.1.18 to be plant specific.	(a) Entergy described the Inservice Inspection (AMP B.1.18) Program as a plant-specific program rather than comparing to the corresponding NUREG-1801 programs (XI.M1 and XI.S3) because the NUREG-1801 programs contain many ASME Section XI table and section numbers which change with different editions of the code. Because of this, comparison with the NUREG-1801 programs generates many exceptions and explanations which detract from the objective of the comparison. The CLB requires that IPEC follow the version of ASME Section XI referenced in 10CFR50.55(a) and approved for use at IPEC. As this is the case, the Inservice Inspection Program is presented as a plant-specific program so it can be judged on its own merit without the distraction of numerous explanations of exceptions due to differing code editions. Since the Inservice Inspection Program is a plant-specific program, comparison of the 10 elements with NUREG-1801 program XI.S3 is not appropriate. Therefore, in the program basis document (IP-RPT-06-LRD02, available for on-site review) the attributes of the program are compared to the ten elements of an aging management program for license renewal as described in NUREG-1800, Table A.1-1. Additional information clarifying specific attributes of the IWF portion of the ISI program is provided below. Inspection methods, frequencies and sampling methods - The ISI Program manages loss of material for ASME Class MC and Class 1, 2, and 3 piping and component supports, anchorages, and base plates by visual examination of components using NDE techniques, frequencies, and sample sizes in accordance with 10 CFR 50.55(a). Class 1 piping supports - visual (VT-3) - 25% of class 1. Class 2 piping supports - visual (VT-3) - 15% of class 2. Class 3 piping Supports - visual (VT-3) - 10% of class 3. For Class 1, 2 and 3 piping supports, the total percentage sample shall be comprised of supports from each system where the individual sample sizes are proportional to the total number of nonexempt supports of each type and function within each system. Supports Other than Piping Supports (Class 1, 2, & 3 and MC) - visual (VT-3) - 100% of the supports. For multiple components other than piping, within a system of similar design, function, and service, the supports of only one of the multiple components are required to be examined. Acceptance Criteria - Acceptance standards for examination evaluations, repair procedures, inservice test requirements, and replacements for ASME Class MC and Class 1, 2, and 3 piping and component supports are in accordance with 10 CFR 50.55(a). The following conditions are unacceptable: (i) deformations or structural degradations of fasteners, springs, clamps, or other support items;

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		(ii) missing, detached, or loosened support items; (iii) arc strikes, weld spatter, paint, scoring, roughness, or general corrosion on close tolerance machined or sliding surfaces; (iv) improper hot or cold positions of spring supports and constant load supports; (v) misalignment of supports; (vi) improper clearances of guides and stops. Identification of unacceptable conditions triggers an expansion of the inspection scope, and reexamination of the supports requiring corrective actions during the next inspection period in accordance with the code. Repair and replacement criteria and procedures are also in accordance with the code. Operating Experience - ISI examinations at IP2 and IP3 were conducted during 2004 and 2005. Results found to be outside of acceptable limits were either repaired, evaluated for acceptance as is, or replacement activities were initiated. Identification of degradation and performance of corrective action prior to loss of intended function are indications that the program is effective for managing aging effects. A self-assessment of the ISI program was completed in October 2004. Review of scope for 2R16 (2004) and 3R13 (2005) verified that the proper inspection percentages had been planned for both outages. A follow-up assessment was held for IP2 in March 2006 to ensure that all inspection activities required to close out the third 10-year ISI interval were scheduled for 2R17 (2006). Confirmation of compliance to program requirements provides assurance that the program will remain effective for managing loss of material of components. QA surveillances in 2005 and 2006 revealed no issues or findings that could impact effectiveness of the program. (b) See response to (a).
58	AMP B.1.18-2 (Inservice Inspection) LRA AMP B.1.18, "Scope of Program" states: "The ISI Program also manages reduction of fracture toughness for valve bodies and pump casing made of cast austenitic stainless steel. Both IP2 and IP3 use ASME Code Case N 481 as approved in Regulatory Guide 1.147 for managing the effects of loss of fracture toughness due to thermal aging embrittlement of CASS pump casing pressure retaining welds. ASME Code Case N 481 has been incorporated in later editions of the code and IP2 will not reference Code Case N 481 in the 4th interval." Explain why a discussion of this specific code case is included.	The Inservice Inspection Program uses nondestructive examination (NDE) techniques to manage reduction of fracture toughness for valve bodies and pump casing made of cast austenitic stainless steel. Since Code Case N-481 has been approved in Regulatory Guide 1.147, it is part of the ASME code and need not be mentioned separately. Therefore, sentences referencing code case N-481 in LRA AMPs B.1.18 and B.1.37 will be removed from the LRA. Clarification to be incorporated into the LRA.
59	AMP B.1.18-3 (Inservice Inspection) LRA AMP B.1.18, "Detection of Aging Effects" states: "The ISI Program will be revised to provide periodic inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump supports." What has been the plant specific operating experience with the degradation of the lubrite plates?	Neither IP2 nor IP3 has plant-specific operating experience with degradation of the Lubrite sliding supports used in the steam generator and reactor coolant pump sliding supports. As discussed in EPRI Report 1002950, Aging Effects for Structures and Structural Components (Structural Tools) Revision 1, Lubrite material resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high radiation, and requires no maintenance. An extensive search of industry operating experience did not identify any instances of Lubrite plate degradation or failure to perform its intended function. Consequently, there are no known aging effects that would lead to a loss of intended function. Nevertheless, as described in LRA AMP B.1.18, the ISI Program will confirm by visual inspection the absence of aging effects for the Lubrite used in the steam generator and reactor coolant pump sliding supports through the period of extended operation. Clarification to be incorporated into the LRA. Commitment # 11.
60	AMP B.1.18-4 (Inservice Inspection) LRA AMP B.1.18, "Detection of Aging Effects"	The ISI program will continue to be implemented in full compliance with the requirements of 10 CFR 50.55a in effect at the beginning of each new 10 year inspection interval.

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	states: "Both IP2 and IP3 have adopted risk informed inservice inspection (RI ISI) as an alternative to current ASME Section XI inspection requirements for Class 1, Category B F and B J welds pursuant to 10 CFR 50.55a(a)(3)(i). The RI ISI was developed in accordance with the EPRI methodology contained in EPRI TR 112657, Rev. B A, "Revised Risk Informed Inservice Inspection Evaluation Procedure." The risk informed inspection locations are identified as Category R A. " During the license renewal period, will the ISI program be implemented in full compliance with the requirements of 10 CFR 50.55a in effect at the beginning of each new 10 year inspection interval?	Letters detailing RI-ISI for IP2 and IP3 category B-F and B-J welds and NRC acceptance letters were provided to the auditor for review. Since use of RI-ISI at IP2 and IP3 has been approved pursuant to 10 CFR 50.55a(a)(3)(i), RI-ISI need not be mentioned separately. Therefore, reference to RI-ISI will be deleted from LRA AMP B.1.18. Clarification to be incorporated into the LRA.
61	AMP B.1.18-5 (Inservice Inspection) LRA AMP B.1.18, "Monitoring and Trending" states: "ISI results are recorded every operating cycle and provided to the NRC after each refueling outage via Owner's Activity Reports. These reports include scope of inspection and significant inspection results. They are prepared and submitted in accordance with NRC accepted ASME Section XI Code Case N 532 1 as approved by RG 1.147." During the license renewal period, will the ISI program be implemented in full compliance with the requirements of 10 CFR 50.55a in effect at the beginning of each new 10 year inspection interval?	ISI results are recorded every operating cycle and provided to the NRC after each refueling outage via Owner's Activity Reports. These reports include scope of inspection and significant inspection results. The ISI program will continue to be implemented in full compliance with the requirements of 10 CFR 50.55a in effect at the beginning of each new 10 year inspection interval. Since Code Case N-532-1 has been approved in Regulatory Guide 1.147, it is part of the ASME code and need not be mentioned separately. Therefore, the sentence referencing code case N-532-1 in LRA AMP B.1.18 will be removed from the LRA. Clarification to be incorporated into the LRA.
62	AMP B.1.19-1 (Masonry Walls) The applicant has identified an enhancement to the Scope of Program, as follows: "Revise applicable procedures to specify that the IP1 intake structure is included in the program." The LR intended function of the IP1 intake structure relates to protection of Appendix R equipment, in accordance with 10 CFR 54.4(a)(3). The intent of the GALL Masonry Wall AMP (XI.S5) is to ensure that a previously documented seismic qualification basis, in accordance with IE Bulletin 80-11, remains valid through implementation of the guidance provided in IN 87-67. Has a documented seismic qualification basis, in accordance with IE Bulletin 80-11, been developed for the masonry components of the IP1 intake structure? If so, provide the documentation at the audit. If not, then this AMP cannot be credited to manage aging for the extended period of operation.	IE Bulletin 80-11, Masonry Wall Design, addressed the potential for problems with the structural adequacy of concrete masonry walls in proximity to or with attachments to safety-related piping or equipment. There are no masonry walls in IP1 intake structures which meet the classification of IE Bulletin 80-11. Thus, no seismic qualification basis in accordance with IE Bulletin 80-11 has been developed for masonry components of IP1 intake structure. IP1 intake structure houses components required for the alternate safe shutdown system, which is credited in the Appendix R safe shutdown analysis. Accordingly, the structure has license renewal intended function for 10 CFR 54.4(a)(3) since it provides support for equipment credited for regulations associated with fire protection (10CFR 50.48). The scope of the GALL Masonry Wall AMP (XI.S5) states: "The scope includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4." Consistent with scope of GALL Masonry Wall AMP (XI.S5), and as described in license renewal application B.1.19, Indian Point Energy Center (IPEC) Masonry Wall Program is an existing program that manages aging effects of all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. Included components are 10 CFR 50.48-required masonry walls. The IPEC Masonry Wall Program, with enhancement, assures the effects of aging are managed such that IP1 intake structure will continue to perform its intended function through the period of extended operation.
63	AMP B.1.22-1 (Bolted Cable Connections) GALL AMP XI.E6 states that testing may include thermography, contact resistance testing, and other appropriate testing methods. In AMP B.1.22, under Detection of Aging Effect element, you have stated that inspection methods may include thermography, contact resistance testing, or other appropriate methods including visual based on plant configuration and industry	Visual inspection is an alternative technique to thermography or measuring connection resistance of bolted connections that are covered with heat shrink tape, sleeving, insulating boots, etc. where the only alterative to visual inspection is destructive examination. This is the same philosophy applied to bolted connections in metal-enclosed bus. As stated in Element 4 of NUREG-1801, Section XI.E4, "As an alternative to thermography or measuring connection resistance of bolted connections, for the accessible bolted connections that are covered with heat shrink tape, sleeving, insulating boots, etc., the applicant may use visual inspection of insulation material to detect surface anomalies, such as discoloration, cracking, chipping or surface contamination."

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	guidance. Explain how visual inspection can detect loosening of bolted cable connections.	AMP B.1.22 is a plant specific program proposed instead of a program that is consistent with GALL XI.E6, Element 4, "Detection of Aging Effects," can be revised as follows to clarify this statement. A representative sample of electrical connections within the scope of license renewal, and subject to aging management review will be inspected or tested prior to the period of extended operation to verify there are no aging effects requiring management during the period of extended operation. The factors considered for sample selection will be application (medium and low voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selected will be documented. Inspection methods may include thermography, contact resistance testing, or other appropriate methods including visual based on plant configuration and industry guidance. Visual inspection should be used instead of destructive examination when other methods cannot be used. The one-time inspection or testing provides additional confirmation to support industry operating experience that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective. An example of where visual inspection may be used is motor connections, where the motor lead is connected to the field cable in a local junction box. Typically these connections are completely covered with field splices, so there is no method to perform connection resistance testing of the connection. The practice would be to not remove the junction box cover when the cable is energized, so thermography would not be an option to determine a loose connection. Another example of using visual inspection would be in remote switchgear panels where the entire connection to the bus is covered with tape or an insulating boot. Clarification to be incorporated into the LRA. Commitment # 14.
64	AMP B.1.24-1 (Instrumention Circuits Test Review) GALL AMP XI.E2 states that this program applies to high-range-radiation and neutron flux monitoring instrumentation cables in addition to other cables used in high voltage, low level signal application that are sensitive to reduction IR. In AMP B.1.24, you only mention about neutron monitoring system cables. (a) Explain why high range monitoring cables are not included in the AMP B.1.24. (b) List other cables used in high voltage, low level signal application. Explain why these cables were not included in the scope of AMP B.1.24.	(a)Although not explicitly listed, the high range radiation monitoring cables were included in AMP B.1.24. The aging management review included neutron monitoring circuits and high range radiation monitoring circuits. Reference Attachment 3 of the electrical AMR report. The program description for AMP B.1.24 uses the phrase (i.e., neutron flux monitoring instrumentation). Since this was meant to be an example, the term "e.g." would have been a more appropriate choice than "i.e.". (b)During the IPA, the only high instrument voltage circuits with low signal values.that were not subject to aging management review were the incore detectors and area radiation monitors. The nonsafety-related incore detectors and the area radiation monitors do not perform a license renewal intended function per 10 CFR 54.4(a)(1), (2), or (3). Therefore, the incore detectors and the area radiation monitors are not included in the scope of the B.1.24 (XI.E2) aging management program. A change will be made to LRA Section B.1.24 for clarification. The recommended change is as follows. The Non-EQ Instrumentation Circuits Test Review Program is a new program that assures the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized equipment environments caused by heat, radiation and moisture; (i.e., neutron flux monitoring instrumentation and high range radiation monitors); can be maintained consistent with the current licensing basis through the period of extended operation. Most sensitive instrumentation circuit cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provides sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results will be performed once every ten years, with the first review occurring before the period of extended operation. For sensitive instrumentation circuit cables that are disconnected during instrument calibrations, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry) will occur at least every ten years, with the first test occurring before the period of extended operation. In accordance with the corrective action program, an engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented

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		to ensure that he intended functions of the cables can be maintained consistent with the current licensing basis through the period of extended operation. This program will consider the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR 109619. Clarification to be incorporated into the LRA.
65	AMP B.1.25-1 (Insulated Cables and Connections) You have stated that a representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected. Describe the technical basis for sampling and action taken if a degradation was found on a representative sample.	This program addresses cables and connections under the premise that a large portion of cables and connections are accessible. This program sample consists of all accessible cables and connections in localized adverse environments. If an unacceptable condition or situation is identified for a cable or connection during this visual inspection, the corrective action process will be used for resolution. As part of the corrective action process a determination will be made as to whether the same condition or situation is applicable to other cables or connections. The program description for B.1.25 will be revised as follows. A representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. The program sample consists of all accessible cables and connections in localized adverse environments. Clarification to be incorporated into the LRA.
66	AMP B.1.26-1 (Oil Analysis) LRA references a June 2006 evaluation of oil analysis practices among Entergy Northeast sites. Provide documentation describing this evaluation (e.g., report) and describe how the evaluation impacted oil analysis practices at Indian Point.	The evaluation report was provided during the on-site audit. Based on the report results, oil analysis frequencies were evaluated with recommended actions. The evaluation resulted in changes to the frequencies of some oil analyses. However, these changes did not affect components in the scope of license renewal that credited the Oil Analysis Program for managing the effects of aging.
67	AMP B.1.26-2 (Oil Analysis) Describe the process for reviewing oil analysis test results and how these reviews ensure that unusual trends are identified and alert levels have not been reached or exceeded.	The results of oil analyses are reviewed by the predictive maintenance group to determine if oil is suitable for continued use until the next scheduled sampling or scheduled oil change. Oil analysis data sheets are provided by an offsite vendor with current and historical analysis results. The data is reviewed to evaluate unusual trends. When degraded conditions are indicated, the predictive maintenance group will take appropriate actions to check the validity of the data and issue a condition report with recommended corrective actions.
68	AMP B.1.26-3 (Oil Analysis) The LRA states that the lubricating oil analysis program is consistent with the program described in GALL, but also identifies six elements as requiring enhancement to achieve this consistency. Provide a more detailed description of past and present lubricating oil monitoring activities at the Indian Point site and the schedule for implementation of enhancements to this AMP.	The enhancements identified for the Oil Analysis Program are not necessary to achieve consistency with the program described in the GALL report. As indicated in LRA Section B.1.26, two of the four enhancements involve adding nonsafety-related components to the program that are not covered in the existing program. The remaining two enhancements involve formalizing in procedures actions that are being informally performed under the existing program. As indicated in the LRA, the existing lubricating oil monitoring activities are essentially the same as those specified in the GALL report. A matrix outlining sampled components and frequencies will be available for review during the on-site audit. Additionally, past oil analysis data sheets will also be available showing historic test results. Enhancements will be implemented prior to the period of extended operation.
69	AMP B.1.26-4 (Oil Analysis) In its description of the exception to NUREG 1801 Element 3, Parameters Monitored or Inspected, the LRA states that flash point has little significance with respect to the effects of aging. Because flash point identifies the presence of volatile and flammable materials, an abnormally low flash point can be indicative of fuel contamination. Provide a technical justification for this exception.	As stated in LRA Section B.1.26 exception note 1, fuel dilution testing is performed in lieu of flash point testing for lubricating oil systems potentially exposed to hydrocarbons. While it is important from an industrial safety perspective to monitor flash point, it is not related to managing the effects of aging. Analyses of filter residue or particle count, viscosity, total acid/base (neutralization number), water content, fuel dilution, and metals content provide sufficient information to verify the oil is suitable for continued use. IPEC performs a fuel dilution test in lieu of flash point testing on emergency diesel generators and IP3 Appendix R diesel generator lubricating oils. There could be two factors that affect the flash point of the oil; the addition of fuel that would lower the flash point or the addition of water that would raise the flash point. The fuel dilution test determines the percent by volume of fuel and the water content test determines the percent by volume of water. By determining the percent by volume of both fuel and water, the analysis can determine the expected change in flashpoint. For oil systems not associated with internal combustion engines, lubricating oil flash point change is unlikely.

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70	AMP B.1.27-1 (One-Time Inspection) GALL recommends that the applicant should schedule the inspection no earlier than ten years prior to the period of extended operation. The LRA states that the inspection will be performed prior to the period of extended operation. The statement should be revised to imply that the inspection will be performed with in the 10 years period prior to the period of extended operation.	For Indian Point Energy Center Unit 2 (IP2), the facility operating license (DPR-26) expires at midnight September 28, 2013. For Indian Point Energy Center Unit 3 (IP3), the facility operating license (DPR-64) expires at midnight December 12, 2015. Since the commitment is being made within the ten years prior to the period of extended operation, the statement that the inspection will be performed prior to the period of extended operation is appropriate and need not be changed.
71	AMP B.1.27-2 (One-Time Inspection) The LRA states that the representative sample size will be based on Chapter 4 of EPRI document 107514, which outlines a method to determine the number of inspections required for 90% confidence that 90% of the population does not experience degradation. Justify how this sampling technique with 90% confidence level provides an effective aging management program with adequate assurance that the applicable components will continue to perform their intended functions through the period of extended operation.	Consistent with NUREG-1801, XI.M32 each inspection activity includes a representative sample of the material and environment population, and, where practical, focuses on the components most susceptible to aging due to time in service and severity of operating conditions. Also, the program provides for increasing the inspection sample size and locations if aging effects are detected. EPRI Report 107514, Age Related Degradation Inspection Method and Demonstration, describes methods used to inspect for age related degradation during the period of extended operation. As stated in this report, one key feature of applying the 90% confidence level is the assumption that none of the inspected items will contain significant aging effects. Consequently, if a single item in the sample population has an aging mechanism of interest, the sample size is increased which will raise the confidence level to greater than 90%. With a combination of proven statistical sampling, focus on susceptible locations, and a mechanism for increasing the sample size, the One-Time Inspection Program provides adequate assurance that the applicable components will continue to perform their intended function through the period of extended operation.
72	AMP B.1.27-3 (One-Time Inspection) What is the specific scope of AMP B.1.27 One Time Inspection that will be implemented to verify the effectiveness of each of the following AMPs: B.1.9, B.1.26, B.1.39, and B.1.40?	B.1.9 Diesel Fuel Monitoring - A representative sample of susceptible components of each material and environment crediting the diesel fuel monitoring program for aging management will be inspected using combinations of nondestructive examinations (including VT-1, ultrasonic, and surface techniques) performed by qualified personnel following procedures that are consistent with Section XI of ASME B&PV Code and 10CFR50, Appendix B to verify the absence of significant corrosion or fouling. B.1.26 *Oil Analysis* - A representative sample of susceptible components of each material and environment crediting the oil analysis program for aging management will be inspected using combinations of nondestructive examinations (including VT-1, ultrasonic, and surface techniques) performed by qualified personnel following procedures that are consistent with Section XI of ASME B&PV Code and 10CFR50, Appendix B to verify the absence of significant corrosion or fouling. B.1.39, B.1.40 and B.1.41 Water Chemistry Programs - A representative sample of susceptible components of each material and environment crediting a water chemistry program for aging management will be inspected using combinations of nondestructive examinations (including VT-1, ultrasonic, and surface techniques) performed by qualified personnel following procedures that are consistent with Section XI of ASME B&PV Code and 10CFR50, Appendix B to verify the absence of significant cracking, corrosion or fouling.
73	AMP B.1.28-1 (One-Time Small Bore Piping) According to GALL, AMP XI.M35, this program is applicable only to plants that have not experienced cracking of ASME Code Class 1 small-bore piping resulting from stress corrosion or thermal and mechanical loading. Justify that both IP2 and IP3 meet this criteria.	Inspections performed to date at IP2 and IP3 have not found cracking of ASME Code Class 1 small-bore piping.
74	AMP B.1.28-2 (One-Time Small Bore Piping) In the Scope section of XI.M35, GALL states that the One-Time Inspection program for ASME Code Class 1 small-bore piping includes locations that are susceptible to cracking. The GALL also states that guidelines for identifying piping susceptible to potential effects of thermal stratification or turbulent penetration are provided in EPRI Report	(a) As stated in LRA Section B.1.28, the One-Time Inspection – Small Bore Piping program will be consistent with NUREG-1801 XI.M35. The program will include a sample selected based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small bore piping locations. EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001, or subsequent revisions of this industry guidance, will be followed for identifying susceptible locations for inspection. (b) See response to (a).

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	1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001. (a) Will this new program to be implemented by Indian Point follow the guidelines of EPRI Report 1000701 for identifying the susceptible locations for inspection? (b) If Indian Point One-Time Inspection Program will not utilize the guidelines of the above EPRI Report, what criteria will be used for identification of susceptible locations? Also justify that this criteria will be equivalent to the EPRI guidelines.	
75	AMP B.1.29-1 (PSPM) What codes and standards are used to implement the Periodic Surveillance and Preventive Maintenance Program? What acceptance criteria are used during the implementation of this program and where are the acceptance criteria defined?	As shown in LRA Section B.1.29, many of the Periodic Surveillance and Preventive Maintenance Program activities include visual or other non-destructive examinations of structures, systems, and components. These examinations are performed in accordance with approved procedures consistent with manufacturers' recommendations. The acceptance criteria, which are specified in the program basis document (Attachment 2, IP-RPT-06-LRD07), and will be included in plant procedures.
76	AMP B.1.29-2 (PSPM) The program description for the Periodic Surveillance and preventive Maintenance program implies that this AMP will be used to manage loss of material for carbon steel components of the cranes, crane rails, and girders. GALL includes AMP XI.M23, Inspection of Heavy Load and Light Load Handling Systems, to manage these components. Describe if the activities of the Indian Point AMP B.1.29 are consistent with the recommendations of the GALL AMP XI.M23. Provide a justification for the activities that are not consistent.	Reactor building crane structural steel girders used in load handling are inspected under the Periodic Surveillance and Preventive Maintenance (PSPM) Program identified in Section B.1.29 of the application. This program includes visual inspections of the crane rails and girders consistent with XI.M23 to manage loss of material. The acceptance criteria in the PSPM Program are "No significant corrosion or wear." The XI.M23 acceptance criteria states, "Any significant visual indication of loss of material due to corrosion or wear is evaluated according to applicable industry standards and good industry practice." PSPM monitoring effectiveness and degrading trends are documented in accordance with 10CFR50 Appendix B. Therefore the aging management activities for crane rails and girders under the above two programs are consistent with the attributes described for the program in NUREG-1801 XI.M23 during the period of extended operation.
77	AMP B.1.29-3 (PSPM) The program description for the Periodic Surveillance and preventive Maintenance program implies that this AMP will be used to manage loss of material for internal surfaces of piping, valves, ducting and other piping components. GALL includes AMP XI.M38, Inspection of Internal surfaces in miscellaneous Piping and Ducting Components, to manage these components. Describe if the activities of the Indian Point AMP B.1.29 are consistent with the recommendations of the GALL AMP XI.M38. Provide a justification for the activities that are not consistent.	The XI.M38 program consists of visual inspections of the internal surfaces of steel piping, piping components, ducting, and other components exposed to environments such as condensation and indoor air that are not covered by other aging management programs. The PSPM program performs internal visual inspections during maintenance activities. These inspections provide timely detection of degradation by confirming the integrity of the internal component surface. Visual inspections are performed by personnel qualified in accordance with site procedures. Inspection intervals are dependent on component material and environment. Acceptance criteria include no significant loss of material or fouling. Unacceptable conditions and degrading trends are documented in accordance with 10CFR50 Appendix B. Aging management activities for internal steel piping, piping components, and ducting included in the Periodic Surveillance and Preventive Maintenance program are consistent with the attributes described for the program in NUREG-1801 XI.M38.
78	AMP B.1.29-4 (PSPM) In the "Evaluation" section of the AMP, the LRA states that the representative sample size will be based on Chapter 4 of EPRI document 107514, which outlines a method to determine the number of inspections required for 90% confidence that 90% of the population does not experience degradation. Justify how this sampling technique with 90% confidence level provides an effective aging management program with adequate assurance that the applicable components will continue to perform their intended functions through the period of extended operation.	The representative sample size used for the Periodic Surveillance and Preventive Maintenance (PSPM) Program is consistent with the sample size discussion for the One-time Inspection Program per NUREG-1801, XI.M32. Periodic inspection activities include a representative sample of the material and environment population, and, where practical, focus on the components most susceptible to aging due to time in service and severity of operating conditions. The representative sample size provides 90% confidence that 90% of the population does not experience degradation. EPRI Report 107514, Age Related Degradation Inspection Method and Demonstration, describes methods used to inspect for age related degradation during the period of extended operation. As stated in this report, one key feature of applying the 90% confidence level is the assumption that none of the inspected items will contain significant aging effects. Consequently, if a single item in the sample population has an aging mechanism of interest, the sample size is increased which will raise the confidence level to greater than 90%. With a combination of proven statistical sampling, focus on susceptible locations,

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		and a mechanism for increasing the sample size, the PSPM program provides more than adequate assurance that the applicable components will continue to perform their intended function through the period of extended operation.
79	AMP B.1.29-5 (PSPM) The program description for the Periodic Surveillance and preventive Maintenance program implies that this AMP will be used to manage loss of material for external surfaces of steel components. GALL includes AMP XI.M36, External Surfaces Monitoring, to manage these components. Describe if the activities of the Indian Point AMP B.1.29 are consistent with the recommendations of the GALL AMP XI.M36. Provide a justification for the activities that are not consistent.	The Periodic Surveillance and Preventive Maintenance Program manages the aging effects of cracking, change in material properties, and fouling on external surfaces. Management of loss of material on external surfaces of some select carbon steel surfaces is also managed by the PSPM program. Aging management activities for external surface monitoring of steel piping, piping components included in the Periodic Surveillance and Preventive Maintenance program are consistent with the attributes described for the program in NUREG-1801 XI.M36.
80	AMP B.1.29-6 (PSPM) Explain how is the "Monitoring and Trending" (element 5 of Evaluation Basis) accomplished in implementing Indian Point AMP B.1.29.	Systems within the scope of the PSPM program are monitored through system engineering activities per site procedures. Results from monitoring activities are evaluated against acceptance criteria and trends are developed by comparing current results to previous results to predict degradation rates. These predictions are used to confirm that loss of component intended function will not occur prior to the next scheduled inspection. Trend data from these activities is used to revise inspection frequencies per the site preventive maintenance processes. All degrading trends will be documented per the IPEC Corrective Action Program in accordance with 10CFR50 Appendix B.
81	AMP B.1.30-1 (Reactor Head Closure Studs) Discuss additional information (e.g., results of testing on the actual stud and nut material) to substantiate that the maximum tensile strength of the reactor closure studs and nuts is less than 170 ksi.	Results of testing shown on available test reports for the actual reactor head closure stud and nut material showed an average measured tensile strength value for each heat number < 170ksi. Documentation of available test results were provided for on-site review.
82	AMP B.1.30-2 (Reactor Head Closure Studs) LRA AMP B.1.30, "Program Description" states: " The NUREG 1801 program, Section XI.M3, Reactor Head Closure Studs is based on ASME Code Edition 2001 including the 2002 and 2003 Addenda. The IPEC ISI program is based on ASME Code Edition 1989, no Addenda with inspection of reactor head closure studs based on the 1998 Edition through the 2000 Addenda. The 1998 Edition through the 2000 Addenda allows surface or volumetric examination when closure studs are removed which is consistent with the requirements of NUREG 1801, Section XI.M3." The staff notes that the GALL AMP XI.M3 program element "Detection of Aging Effects" requires both surface and volumetric examination of studs when removed. Provide an explanation why this is not considered as an exception to the GALL program.	The following passage of NUREG-1801AMP XI.M3 program element "Detection of Aging Effects" appears to be incorrect because ASME Section XI, Code Edition 2001 including the 2002 and 2003 addenda allows surface or volumetric examination when closure studs are removed. NUREG-1801, Section XI.M3 states, "Components are examined and tested as specified in Table IWB-2500-1. Examination category B-G-1, for pressure-retaining bolting greater than 2 in. diameter in reactor vessels specifies volumetric examination of studs in place, from the top of the nut to the bottom of the flange hole, and surface and volumetric examination of studs when removed." It appears that the phrase "surface and volumetric examination of studs when removed" should have been changed to "surface or volumetric examination of studs when removed" when the ASME code version cited in NUREG-1801 was changed. Since the IPEC program is consistent with Table IWB-2500-1 examination category B-G-1 in ASME Code Edition 2001 including the 2002 and 2003 Addenda it is consistent with NUREG-1801.
83	AMP B.1.31-1 (Reactor Vessel Head Penetration Inspection) LRA AMP B.1.31, "Program Description" states: " This program was developed in response to NRC Order EA 03 009. The ASME Section XI, Subsection IWB Inservice Inspection and Water Chemistry Control Programs are used in conjunction with this program to manage cracking of the reactor vessel head penetrations. Detection of cracking is accomplished through implementation of a combination of bare metal visual examination (external surface of head) and non visual examination (underside of head)	(a) At the last refueling outage (Spring, 06), IP2 calculated EDY corresponding to the moderate susceptibility category. At the last refueling outage (Spring, 07), IP3 calculated EDY corresponding to the high susceptibility category. IPEC will update the IP2 EDY calculations prior to the next refueling outages as required by the Order. (b) A relaxation request was granted to perform a BMV examination of no less than 95 percent of the RPV head surface rather than 100 percent because a small area is partially obscured by a reflective metal insulation (RMI) support ring located downslope from the outermost RPV head penetrations. (Ref. COR-04-0244, COR-05-0530) A relaxation request was granted wherein the inspection coverage NDE, using ultrasonic testing (UT) techniques, of head penetration nozzles is limited by a threaded section that is for some penetrations less than the 1 inch below the lower

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	techniques. Procedures are developed to perform reactor vessel head bare metal inspections and calculations of the susceptibility ranking of the plant." (a) What are the susceptibility ranks [or the effective degradation years (EDY)] for both IP2 and IP3? (b) Has Entergy requested relaxation of the requirements in the revised Order EA 03 009 for either IP unit? If yes, discuss the technical bases for the relaxation requests. (c) Discuss in detail the implementation of NRC Order EA 03 009 for both IP2 and IP3, with respect to detection of aging effects. (d) How is this AMP coordinated with the Boric Acid Corrosion Prevention Program (AMP B.1.5)?	boundary limit. IPEC performs ultrasonic testing (UT) from the inside surface of each RPV head penetration nozzle from 2 inches above the J-groove weld and extending down the nozzle to at least the top of the threaded region or further down the threaded region to the extent allowed by technology and geometry. (Ref. COR-06-00111, COR-06-00373) (c) IPEC has fully implemented the requirements of EA-03-009 with approved relaxation requests. The aging effect managed is PWSCC, which typically initiates in the penetration nozzle or in the nozzle J-groove attachment weld. Every two refueling outages for IP2 and every refueling outage for IP3, BMV examination of at least 95% of the reactor head surface including those areas upslope and downslope of the insulation and ventilation shroud support ring is performed to identify and document evidence of boric acid deposits and head surface degradation. A 360 degree visual inspection around each of the reactor head penetrations is performed to identify and document evidence of boric acid deposits at the annulus between the penetration and the vessel head . Visual inspections of pressure retaining components above the reactor vessel head are performed. Every two refueling outages for IP2 and every refueling outage for IP3, examinations consisting of eddy current testing and ultrasonic test are performed on the wetted surfaces on the ID side of penetration nozzles. As described in outage inspection reports, no indications of reactor pressure vessel upper head degradation or primary reactor coolant boundary leakage at the reactor vessel head penetrations has been discovered. (d) The Boric Acid Corrosion Control Program complements the Reactor Vessel Head Penetration Inspection Program by performing a visual inspection of the reactor vessel head at locations specified by procedures 2-PT-R156, "Boric Acid Leakage and Corrosion Inspection" and 3-PT-114A, "Reactor Vessel and Closure Head Boric Acid Leakage and Corrosion Inspection". Corporate procedure EN-DC-319, "Inspection and Evaluation of Boric Acid Leaks" provides general guidance for both head penetration inspections and other boric acid leak detection. Inspection for boric acid corrosion is coordinated with reactor vessel disassembly and other inspections required by EA-03-009 as directed by implementing procedures and outage scheduling. COR-04-0244, COR-05-0530, COR-06-00111, COR-06-00373 were provided.
84	AMP B.1.34-1 (Service Water Integrity) Since this aging management program (AMP) may include non safety related components, such as piping, it typically has a broader scope than the GL 89 13 program. Describe the difference in scope between the Indian Point site GL 89-13 program and this (AMP) and, if applicable, describe how the implementation of GL 89-13 recommendations was extended to bound systems and components within the scope of this AMP.	The GL 89-13 program includes safety-related components that are cooled by the service water systems (heat exchangers) as well as the safety-related components that supply the cooling water for heat removal (i.e., pumps, piping, valves, etc.). The Service Water Integrity Program scope includes all GL 89-13 program components, as well as, additional components in the scope of license renewal that contain service water regardless of their safety classification. The service water systems at IPEC supply both safety-related and nonsafety-related loads. The nonsafety-related components and loads included in the Service Water Integrity Program consist of main turbine auxiliary cooling loads such as turbine lube oil coolers, stator water coolers, seal oil coolers, and hydrogen coolers as well as other loads such as turbine hall closed cooling water heat exchangers In addition, the GL 89-13 and Service Water Integrity programs do not include components that contain raw water not supplied by the service water systems such as the circulating water and traveling screen wash water systems. The types of components and their materials included in the GL 89-13 program and the Service Water Integrity Program are the same. As such, the methodology of periodic inspection and maintenance applies for both. GL 89-13 is not extended to nonsafety-related heat exchangers that are included in the Service Water Integrity Program. Periodic inspections are sufficient to manage aging effects of the nonsafety-related heat exchangers since they do not have a license renewal component intended function of heat transfer. The Service Water Integrity Program includes activities, such as chemical treatment using biocides and chlorine, which apply to the service water system as a whole. Periodic visual inspections and inspections using non-destructive examination (NDE) techniques are used to manage loss of material in SW components regardless of safety classification. The GL 89-13 program includes inspections of some nonsafety-related components in the service water system, such that the inclusion of these additional components in the Service Water Integrity program is reasonable.
85	AMP B.1.36-1 (Stuctures Monitoring) From the applicant's description of the B.1.36 AMP "Structures Monitoring" in LRA Appendix B,	a) The following structures and their structural components are inspected as part of the existing structures monitoring program (Ref. Aging Management Program Evaluation Report IP-RPT-06-LRD08, section 3.3).

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	the staff cannot identify the complete scope of the program. Very significant enhancements to the " Scope of Program" are identified. However, there is no description of the scope of the existing structures monitoring program, and there is no explanation why such major enhancements to the program scope are needed for license renewal. The staff reviewed Section 2.4 of the LRA, to better understand the intended functions of the structures that are being added to the scope. While almost all of the added structures serve a license renewal intended function for 10 CFR 54.4(a)(3), about half (11) of these structures also serve license renewal intended functions for 10 CFR 54.4(a)(1) and/or 10 CFR 54.4(a)(2). In accordance with NRC guidance (RG 1.160) and industry guidance (NEI 93-01) these structures would be expected to be included in the current existing program. (a) Describe the structures and structural components inspected as part of the existing structures monitoring program. (b) Explain why eleven (11) structures listed in the "Scope of Program" enhancement have intended functions for 10 CFR 54.4(a)(1) and/or 10 CFR 54.4(a)(2).	• auxiliary feedwater pump building (IP2/3) • boric acid evaporator building (IP2) • city water meter house • condensate storage tanks foundation (IP2) • containment building (also known as vapor containment (IP2/3) • control building (IP2/3) • electrical tunnel (IP2/3) • emergency diesel generator building (IP2/3) • fan house (IP2/3) • fuel storage building (IP2/3) • gas turbine generator No. 1, 2 and 3 enclosures • gas turbine generator No. 2 and 3 fuel tank foundations • intake structure (also known as screenwell structure) (IP1/2/3) • power conversion equipment building (IP3) • primary auxiliary building (IP2/3) • primary water storage tank foundation (IP2) • radiation monitoring enclosure (IP2) • refueling water storage tank foundation (IP2) • superheater building (IP1) • transformer switchyard support structures (IP3) • transmission towers (SBO recovery path) and foundations (IP2/3) • turbine building (IP1/2/3) and heater bays (IP2/3) • utility tunnel (IP1) b) City Water Storage Tank Foundation The foundation supports the in-scope city water storage tank and meter house. The tank is in-scope because it provides a source of water for the auxiliary feedwater system for both IP2 and IP3 and supplies emergency water for safety injection, residual heat removal, and charging pumps. The city water storage tank foundation has intended function for 10 CFR 54.4(a)(2). Condensate Storage Tank Foundation (IP3) The condensate storage tank foundation supports the condensate storage tank. The foundation has intended functions for 10 CFR 54.4(a)(1) and (a)(2). Containment Access Facility and Annex (IP3) The containment access facility and annex is located adjacent to the primary auxiliary building (PAB). The containment access facility and annex is Class III except for the structural steel portion interfacing with the primary auxiliary building (PAB), which is seismic Class I. The structure has intended function for 10 CFR 54.4(a)(2). Discharge Canal The discharge canal carries the safety-related service water system discharge to the river. Three backup service water pumps, which provide cooling water from the discharge canal in the unlikely event that the service water intake structure is damaged, are supported on a slab spanning the walls of the canal. The portion of the discharge canal wall that is adjacent to the service water pipe chase is seismic Class I and is part of the ultimate heat sink. The structure has intended functions for 10 CFR 54.4(a)(1) and (a)(2). Primary Water Storage Tank Foundation (IP3) The primary water storage tank foundation provides the main support for the 165,000 gallon primary water storage tank. The tank supplies demineralized water for the primary water makeup system. The primary water storage tank foundation is a Seismic Class I reinforced concrete spread footing supporting the primary water storage tank. The structure has intended functions for 10 CFR 54.4(a)(2). Refueling Water Storage Tank Foundation (IP3) The refueling water storage tank foundation provides the main support for the 350,000 gallon refueling water storage tank. The tank supplies borated water to the refueling canal, safety injection pumps, the residual heat removal pumps, and the containment spray pumps for the loss-of-coolant accident. The structure has intended functions for 10 CFR 54.4(a)(1). Service Water Pipe Chase (IP3) The service water pipe chase provides protection of service water lines that span across the discharge canal. The structure provides protection of the service water valves and associated piping. This structure has intended functions for 10 CFR 54.4 (a)(1) and (a)(2).

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		Service Water Valve Pit (IP3) Service water valve pit for each intake structure is provided for protection of service water components. This structure has intended functions for 10 CFR 54.4 (a)(1) and (a)(2). Superheater Stack (IP1) The superheater building is adjacent to but physically separated from the control building. The superheater stack is located on top of the Unit 1 superheater building. The exterior walls are masonry or metal siding. The superheater building was originally classified as seismic Class III, but it is utilized by Unit 2 in a safety function and is now classified as seismic Class I. This structure has intended functions for 10 CFR 54.4(a)(1) and (a)(2). Waste Holdup Tank Pit (IP2) The waste holdup tank pit houses the waste holdup tank, which serves as the collection point for all liquid radwaste. This structure is conservatively credited for performing the following intended functions for 10 CFR 54.4(a)(2). Provide functional support to nonsafety-related components whose failure could result in potential offsite releases. Waste Holdup Tank Pit (IP3) The waste holdup tank pit (WHTP) is two adjacent underground structures joined together to form a single structure. It is adjacent to the primary water storage tank and the radioactive machine shop. The structure houses waste holdup tanks No. 31, 32 and 33 each in their own separate. The structure has the following intended functions for 10 CFR 54.4(a)(2). Provide functional support to nonsafety-related components whose failure could result in potential offsite releases
86	AMP B.1.36-2 (Structures Monitoring) The second enhancement to AMP B.1.36 under " Scope of Program" indicates that "procedures will be revised to clarify that in addition to structural steel and concrete", 13 commodities "are inspected for each structure, as applicable." The staff notes that the specific commodities listed would be expected to be included in the current existing program if they are safety-related or important to safety. The staff is unclear what commodities are currently being inspected in the existing program. (a) Describe the structural commodities inspected as part of the existing structures monitoring program. (b) Explain why the 13 commodities are identified as an enhancement to the "Scope of Program."	(a) The structural commodities inspected as part of the existing structures monitoring program include structural steel (beam, columns, end connections), support steel (instruments racks, base plates, etc.), concrete surfaces, instrument racks . Individual inspection checklists are provided in the program procedures for each commodity. (Ref. ENN-DC-150, Section 5.5 and Attachments 9.2 and 9.4) (b) While many of the listed commodities are routinely inspected as part of the current structures monitoring program (AMP B.1.36), they are not explicitly identified in the program procedures. Thus, the purpose of the enhancements is to ensure these items (including their anchorages) are identified explicitly in the program. For example, the existing SMP includes inspection of concrete damage due to vibrating equipment, which addresses equipment pads and foundation identified in the enhancement (Ref. ENN-DC-150, Section 5.7 [2] and Attachment 9.4). In LRA Section B.1.36.2 and in Commitment 25, add "(including their anchorages)" in paragraph discussing the enhancemnts to SMP for IP2 and IP3. Clarification to be incorporated into the LRA.
87	AMP B.1.36-3 (Structures Monitoring) An enhancement to AMP B.1.36 under "Detection of Aging Effects" is to monitor groundwater for aggressiveness to concrete. Sulfates, pH and chlorides will be monitored. Ground water testing is to be conducted at least every five (5) years, by taking samples from a well that is representative of groundwater surrounding below-grade site structures (a) Describe past and present groundwater monitoring activities at the Indian Point site, including the sulfates, pH and chlorides readings obtained; and the location(s) where test samples were/are taken relative to the safety-related and important-to-safety embedded concrete foundations. (b) Explain the technical basis for concluding that testing a single well every five (5) years is	a) There is sufficient number of analytical results to ensure that the ground water is being properly monitored. Large numbers of groundwater wells located adjacent to the structures have been sampled and were analyzed for sulfate and chloride at a contract laboratory, with pH having been determined at the time of sample collection. The data indicates that the ground water is non-aggressive (pH>5.5, Chloride <500 ppm and Sulfate <1500 ppm). Several samples taken along the facility waterfront and adjacent to the discharge canal were noted to have higher than normal levels of chloride. Given the location of samples, these higher than normal levels are believed to be due to the salinity of the brackish Hudson River water at the Indian Point location of the river. In all cases pH results are >5.5 and sulfate concentration < 1500 mg/L. Ground water samples will continue to be obtained on a quarterly basis for one calendar year in order to fully characterize these parameters (Chloride, Sulfate, and pH) for the groundwater at IPEC to account for any seasonal variation. The selected sample locations will provide representative sample of the ground water in the vicinity of the structures. A review of the several hundred ground water pH values collected in late 2005 to present reveal that the ground water had a pH of >5.5 in all cases except four. In those four cases pH was found to be <5.5 SU. All four of these low pH samples were obtained *from the same sample point on the same day. To date all subsequent samples taken* from this sample point were found to have a pH >5.5 SU.

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	sufficient to ensure that safety-related and important-to-safety embedded concrete foundations are not exposed to aggressive groundwater.	There is sufficient number of monitoring wells being sampled at various locations to ensure monitoring the ground water. And, the results are being properly evaluated in order to characterize the ground water across the site (in vicinity of the safety-related structures). The sample data and well map are available on site for review. b) At least five (5) wells will be tested. A sample frequency of 5 years in a limited number of wells (at least 5 wells) adjacent to safety structures and those falling under 10 CFR 54.4 (a)(1) and 10 CFR 54.4 (a)(2) would be sufficient to confirm non-aggressive nature of the ground water. The large sample population for the initial characterization, the diverse locations from which the samples were obtained and the seasonality of sample collections contribute to our confidence in the understanding of the nature of the ground water. Additionally, we would not normally expect to see the ground water conditions change unless an extraordinary event occurred such as a major withdrawals (such as significant pumping out the ground water) or injections of water on the Site or in the vicinity of the Site. Finally, the three structural inspections performed in five year intervals showed no major change in structural integrity from inspection to inspection. Information to be incorporated into the LRA.
88	AMP B.1.36-4 (Structures Monitoring) In LRA Appendix B, Table B-2, the applicant indicates that "This program [GALL AMP XI.S7] is not credited for aging management. The Structures Monitoring Program manages the effects of aging on the water control structures at IPEC." GALL AMP XI.S7 offers this option, provided all the attributes of GALL AMP XI.S7 are incorporated in the applicant's Structures Monitoring Program. (a) Identify the specific water control structures that have an intended function for license renewal, and are included in the scope of AMP B.1.36. (b) Describe the attributes of AMP B.1.36 that pertain to aging management of water control structures. (c) Explain how these attributes of AMP B.1.36 encompass the attributes of GALL AMP XI.S7, without exception.	(a) The water control structures at Indian Point Energy Center (IPEC) which have an intended function for license renewal and are included (or will be included) in the scope of AMP B.1.36 (Structures Monitoring) are intake structure (including intake structure enclosure) and discharge canal. The discharge canal is not explicitly specified in the structures monitoring procedures. An enhancement identified for AMP B.1.36 will explicitly specify the discharge canal. (Ref. LRA section 2.4.2 and B.1.36) (b) AMP B.1.36 (Structures Monitoring Program) is an existing program that performs inspections in accordance with 10 CFR 50.65 (Maintenance Rule) as addressed in Regulatory Guide 1.160 and NUMARC 93-01. Periodic inspections are used to monitor the condition of water control structures and structural components to ensure there is no loss of intended function. If established criteria as specified in maintenance rule scoping documents are exceeded the affected system is monitored in accordance with a 10 CFR 50.65 (a)(l) action plan. The parameters monitored or inspected were selected based on information included in industry codes, standards and guidelines, and also consider industry and plant-specific operating experience. Inspections of steel and concrete portion of accessible water control structures are performed at five-year intervals and inspections of normally inaccessible areas are performed using special tools or inspection of adjacent areas when possible. More frequent inspections may be performed based on past inspection results, industry experience, or exposure to a significant event. Inspection methods, inspection schedule, and inspector qualifications ensure that aging degradation will be detected and quantified before loss of intended functions. Inspection methods, inspection schedule, and inspector qualifications are based on information provided in industry codes, standards and guidelines, and also consider industry and plant-specific operating experience. The acceptance criteria were selected to ensure that the need for corrective actions is identified before loss of intended functions. Acceptance criteria were established considering information provided in industry codes, standards, and guidelines including NE1 96-03, ACI 201.1 R-92, and ACI 349R-85. Industry and plant-specific operating experience was also considered. IPEC applies requirements of 10 CFR Part 50 Appendix B to the Structures Monitoring Program through use of the IPEC corrective action program. (c) The Structures Monitoring Program (AMP B 1.36) is consistent with the program described in NUREG-1801, Section XI.S6, Structures Monitoring Program with enhancements listed in LRA section B.1.36. The SMP attributes are consistent with the XI.S7 program attributes that are applicable to the in-scope IPEC water control structures. 1) Scope – The scope of the GALL XI.S7 program applicable to IPEC is the intake structure and discharge canal. There are no earthen structures at IPEC in the scope of license renewal. The intake structure is included in the scope of the Structures Monitoring Program. The discharge canal will be explicitly added to the program as an enhancement to AMP B.1.36. (Ref. LRA section 2.4.2 and B.1.36)

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		2) Preventive actions – The GALL XI.S7 program includes no preventive actions. AMP B.1.36 is consistent with preventive actions. 3) Parameters Monitored – The aging effect requiring management for concrete structural components of the intake structure is loss of material which is consistent with GALL Volume 2 item III.A6-7. The parameters monitored from the GALL XI.S7 program applicable to loss of material are consistent with those monitored by the Structures Monitoring Program. The guidance for inspections of concrete in Section C.2 of RG 1.127 is consistent with the guidance in ACI 349.3 used in the Structures Monitoring Program. Based on the above discussion, the parameters monitored include loss of material, cracking, movement (settlements and deflections). Since there are no earthen structures at IPEC in scope of the license renewal, GALL XI.S7 attributes applicable to earthen structures are not applicable for IPEC water control structures. 4) Detection of Aging – GALL XI.S7 identifies visual inspection methods as the primary method used to detect aging. The Structures Monitoring similarly uses visual inspection methods as the primary method used to detect aging in concrete structural components. GALL XI.S7 identifies inspection intervals of five years. The Structures Monitoring Program identifies similar inspection intervals of five years for accessible areas and opportunistic inspections for buried components. Guidance will be added to the Structures Monitoring Program to inspect inaccessible concrete areas that are exposed by excavation for any reason. 5) Monitoring and Trending – Monitoring is by periodic inspection for both the GALL XI.S7 and Structures Monitoring Programs. 6) Acceptance Criteria – Acceptance criteria in NUREG-1801, XI.S7 says plant-specific acceptance criteria based on Chapter 5 of ACI 349.3R-96 are acceptable. Appropriate guidance is provided in the Structures Monitoring Program to ensure corrective measures are identified prior to loss of intended function. The guidance in the Structures Monitoring Program includes reference to ACI 349.3R-96. XI.S7 acceptance criteria related to earthen structures are not applicable. 7-9) The corrective actions, confirmation process and administrative control attributes of the Structures Monitoring Program and the GALL XI.S7 program are consistent. 10) Operating Experience – The operating experience relevant to the effectiveness of the Structures Monitoring Program is presented in Appendix B of the application and is consistent with the operating experience described in GALL XI.S7. Therefore, the attributes of the NUREG-1801 XI.S7, Water Control Structures, aging management program pertaining to the intake structure are incorporated within the AMP B.1.36 (Structures Monitoring Program). The following is added to commitment 25: "Enhance the Structures Monitoring Progrm for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once every 5 years. Information to be incorporated into the LRA.
89	AMP B.1.36-5 (Structures Monitoring) What is Entergy's schedule for implementing the enhancements to AMP B.1.36?	Enhancements to the Structures Monitoring Program (AMP B.1.36) will be implemented prior to the period of extended operation. See Commitment #25
90	AMP B.1.39-1 (Water Chemistry-Auxiliary System) Describe past and present surveillance tests, sampling, and analysis activities for managing the effects of aging on components within the scope of this AMP.	Recent monthly tests of stator cooling water samples have been within specification. Monthly stator cooling water analysis will continue per the requirements of procedure 0-CY-2510, "Closed Cooling Water Chemistry Specifications and Frequencies" The LRA credits both the Water Chemistry Control – Auxiliary Systems and Periodic Surveillance and Preventative Maintenance (PSPM) programs to manage loss of material for the NaOH tank. Since thickness measurements are performed every five years under the PSPM Program, use of the water chemistry control – auxiliary systems is not required. Therefore, IP-RPT-06-LRD07 and the LRA will be revised to remove the Water Chemistry Control – Auxiliary Systems Program as an aging management program for the NaOH tank. Auxiliary steam supply is cross-connected so that IP2 or IP3 can support the steam

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		requirements of either unit from the main steam systems. Components in the house service boiler systems subject to aging management review are exposed to main steam during normal operation and are managed by the Water Chemistry Control – Primary and Secondary Program and not the Water Chemistry Control – Auxiliary Systems Program as stated in the LRA. Therefore, IP-RPT-06-LRD07 and the LRA will be revised to remove the Water Chemistry Control – Auxiliary Systems Program as an aging management program for the house service boiler systems. Water chemistry parameters for house service boiler components are maintained per EPRI guideline TR-102134, "Pressurized Water Reactor Secondary Chemistry Guidelines" . Recent test of secondary water chemistry parameters have been within specification or corrective actions have been performed to return parameters to acceptable levels per prescribed action levels. Parameters are maintained per the requirements of Procedure 0-CY-2410, "Secondary Chemistry Specifications". Recent chemistry data was available for review. Information to be incorporated into the LRA.
91	AMP B.1.39-2 (Water Chemistry-Auxiliary Systems) Describe the procedures used to perform surveillance activities and the basis for acceptance criteria and sample / test frequencies.	Stator cooling water systems are high purity systems in which poor oxygen control can cause an increase in copper corrosion products. Based on this experience, stator cooling water is monitored monthly for conductivity and copper. Refer to Procedure 0-CY-2510, Closed Cooling Water Chemistry Specifications and Frequencies and 2-SOP-26.7, Generator Stator Cooling Water System for more information. The LRA credits both the Water Chemistry Control – Auxiliary Systems and Periodic Surveillance and Preventative Maintenance (PSPM) programs to manage loss of material for the NaOH tank. Since thickness measurements are performed every five years under the PSPM program, use of the Water Chemistry Control – Auxiliary Systems Program is not required. Therefore, IP-RPT-06-LRD07 and the LRA will be revised to remove the Water Chemistry Control – Auxiliary Systems Program as an aging management program for the NaOH tank. Auxiliary steam supply is cross-connected so that IP2 or IP3 can support the steam requirements of either unit from the main steam systems. Components in the house service boiler systems subject to aging management review are exposed to main steam during normal operation and are more appropriately managed by the Water Chemistry Control – Primary and Secondary Program and not the Water Chemistry Control – Auxiliary Systems Program as stated in the LRA. Therefore, IP-RPT-06-LRD07 and the LRA will be revised to remove the Water Chemistry Control – Auxiliary Systems Program as an aging management program for the house service boiler systems. Water chemistry parameters for house service boiler components are maintained per EPRI guideline TR-102134, "Pressurized Water Reactor Secondary Chemistry Guidelines". Parameters are maintained per the requirements of Procedure 0-CY-2410, "Secondary Chemistry Specifications" available for review during the audit. Information to be incorporated into the LRA.
92	AMP B.1.40-1 (Water Chemistry-Closed Cooling) The LRA takes an exception to the GALL recommendation for detection of aging effects through performance and functional testing. As a result, this program credits preventive measures to manage the effects of aging. Provide objective evidence (e.g., plant specific operating experience) which demonstrates that the existing preventive measures will adequately manage the effects of aging in the closed cooling water system components that are within the scope of license renewal.	A recent QA audit found that closed cooling water chemistry parameters are maintained within industry guidelines and a recent routine inspection of components in a closed cooling water system found no evidence of active corrosion. LRA section B.1.27, One-Time Inspection, describes inspections planned to verify effectiveness of the water chemistry control programs to ensure that significant degradation is not occurring and component intended function is maintained during the period of extended operation. The results of these inspections will provide objective evidence to demonstrate that the existing preventive measures will adequately manage the effects of aging in the closed cooling water system components that are within the scope of license renewal. Please see the response to audit question 95 (AMP B.1.40-4) for additional information regarding component inspections in closed cooling water systems.
93	AMP B.1.40-2 (Water Chemistry-Closed Cooling) The LRA states that in June 2003, CCW corrosion inhibitor (molybdate concentration) was found to be out of specification and that corrective actions were taken to restore the molybdate concentration to specification. However, the LRA does not indicate if surveillance practices (e.g., sampling)	The IP2 CCW system Molybdate is administratively controlled within the 400-800 ppm range to ensure it remains within the 200-1000 ppm range recommended in the EPRI Closed Cooling Water Guidelines (EPRI TR 1007820). In accordance with EPRI TR-1007820, site procedures contain two action levels. 1) If the Molybdate level falls below 200 ppm the system should be restored to above 200 ppm within 90 days. 2) If the Molybdate level falls below 160 ppm the system should be restored to above 200 ppm within 30 days. If these actions are not accomplished, an engineering evaluation must be performed to determine the impact of the condition

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	were also modified as a result of this occurrence. Provide a description of past and present surveillance activities and, if applicable, provide a justification if the surveillance practices or frequencies were not revised as a result of this event.	on the long-term reliability of the system. On 3/21/03, a 113 ppm Molybdenum concentration (which correlates to an ~188 ppm Molybdate concentration) was observed. Subsequently, on 4/15/2003, a 131 ppm concentration was observed. The low concentration occurred due to dilution when water was added to the system to compensate for leaks and work activities. Leaks were repaired, Molybdate was added to the system to restore the concentration to the normal range, and the normal monthly sample frequency was temporarily increased (two samples were taken the next week) to verify that the concentration remained within the normal range. The concentration on 4/22/03 was 418 ppm and the concentration on 4/23/03 was 425 ppm, indicating that proper control had been restored. A few weeks later (5/14/2002), a 395 ppm concentration was observed. While this value does not require action per the EPRI guidelines, it is outside the administrative control range, so Molybdate was again added. Since that time, monthly samples (June 2003 to August 2007) have shown that the IP2 CCW Molybdate concentration has remained above the action level threshold and, except for one reading of 377 ppm in May 2006, has remained within the 400-800 ppm administrative control range. As sustained Molybdate concentrations below 160 ppm could initiate system material degradation, EPRI TR 1007820 and site procedures direct that an engineering evaluation be performed to determine the impact of the condition on the long-term reliability of the system if the condition persists for more than 30 days after the first sample below 160 ppm. Since the Molybdate concentration in the IP2 CCW system was returned to 418 ppm seven days after the sample below 160 ppm and has remained above the threshold since that time, evaluation of the impact of the condition on long-term reliability is not necessary and increased sampling is not warranted. Sample results since June 2003 have confirmed the adequacy of the established sampling frequency.
94	AMP B.1.40-3 (Water Chemistry-Closed Cooling) The LRA states: "Continuous program improvement provides assurance that the program will remain effective for managing loss of material of components." However, the LRA only cites one QA audit observation to support this conclusion. Provide additional information to support this conclusion.	In addition to the QA audit of the plant chemistry program in August 2003 that was mentioned in the LRA, similar audits in June 2005 and September 2006 support the conclusion that continuous program improvement provides assurance that the Water Chemistry Control - Closed Cooling Water Program will remain effective for managing loss of material of components. The June 2005 audit concluded that the program is effective in implementing applicable regulations, industry standards and the quality assurance program manual. Strengths were noted in the areas of leadership, accountability, training, and review of industry operating experience. The September 2006 audit concluded that closed cooling water systems are treated and controlled to industry guidelines. Improvements were noted in the use of the condition reporting process and strengths were noted in the area of chemistry data trending.
95	AMP B.1.40-4 (Water Chemistry-Closed Cooling) The exception to GALL, Element 5, Monitoring and Trending, states that visual inspections are not performed. Provide a technical justification for not performing visual inspections recommended in GALL.	The Water Chemistry Control – Closed Cooling Water Program is a preventive program. EPRI Report TR-1007820 refers to inspections performed in conjunction with maintenance activities, which are not specifically included as part of this program. However, components cooled by closed cooling water systems are routinely inspected as part of an eddy current inspection program. These heat exchangers receive a visual inspection in addition to eddy current testing that would detect aging effects and confirm the effectiveness of the Water Chemistry Control-Closed Cooling Water Program. Some of the heat exchangers receiving visual inspections include: • IP2 and IP3 Closed Cooling Water 21/22CCHX and ACAHCC1/2 • IP2 and IP3 Instrument Air Closed Cooling Water 21/22CWHX and SWM-CLC-31/32-HTX • IP2 and IP3 EDG Jacket Water Coolers 21/22/23EDJC and EDG-31/32/33-EDG-JWHTX • IP2 Conventional Closed Cooling 21/22THCCSHX • IP3 Turbine Hall Closed Cooling SWT-CLC-31/32-HTX In addition to these completed inspections, LRA Section B.1.27, One-Time Inspection, describes future inspections planned to verify effectiveness of the water chemistry control programs to ensure that significant degradation is not occurring and component intended function is maintained during the period of extended operation. This will include areas most susceptible to corrosion such as stagnant areas.

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		Clarification to be incorporated into the LRA
96	AMP B.1.40-5 (Water Chemistry-Closed Cooling) GALL, Element 2, preventive actions, states that system corrosion inhibitor concentrations should be maintained within limits specified in EPRI TR 107396. Since this element is not identified in the exception, it is assumed that the IP program is consistent with NUREG 1801. Describe the basis for specified corrosion inhibitor concentration limits.	The IP Water Chemistry Control – Closed Cooling Water Program will be consistent with NUREG-1801. The program maintains system corrosion inhibitor concentrations within specified guidelines of EPRI Report TR-1007820, Rev. 1 to minimize corrosion and SCC. EPRI TR-1007820 supersedes TR-107396 referenced in NUREG-1801.
97	AMP B.1.40-6 (Water Chemistry-Closed Cooling) For each program attribute having an exception to GALL, provide a detailed, line by line, comparison of the criteria recommended in GALL (e.g., EPRI TR 107396) against the criteria / industry standard (e.g., EPRI TR 1007820) that have been implemented.	The Water Chemistry Control – Closed Cooling Water Program is based on EPRI guidelines for closed cooling water issued as EPRI TR-1007820, 'Closed Cycle Cooling Water Chemistry,' Rev. 1, dated April 2004. This guideline supersedes EPRI TR-107396, 'Closed Cycle Cooling Water Chemistry Guideline,' Revision 0, issued November 1997, referenced in NUREG-1801. Revision 1 of the EPRI guideline is significantly more directive than Revision 0 and incorporates action levels with established thresholds for specific actions required. Revision 1 specifically establishes recommended monitoring frequencies and clearly identifies expected control parameter values. The LRA indicates that Water Chemistry Control – Closed Cooling Water Program attributes 3, 4, 5, and 6 have an exception to GALL. In all four cases, the exception is due to the fact that NUREG-1801 recommends the use of performance and functional testing to ensure acceptable function of the CCCW systems, while the IPEC Water Chemistry Control – Closed Cooling Water Program does not include performance and functional testing. The exception is the same regardless which revision of the EPRI guideline is used because neither revision of the EPRI guideline recommends that equipment performance and functional testing should be part of a water chemistry program. Rather, the EPRI reports state (Section 5.7 in EPRI report TR-107396 and Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. Please see the response to audit question 95 (AMP B.1.40-4) for additional information regarding component inspections in closed cooling water systems.
98	AMP B.1.41-1 (Water Chemistry-Primary & Secondary) It is noted that Indian Point AMP B.1.41, Water Chemistry Control - Primary and Secondary, is based on the guidelines provided in EPRI TR-105714, Revision 5 and EPRI TR-102134, Revision 6. The corresponding GALL AMP XI.M2, Water Chemistry, is based on the guidelines provided in Revision 3 of EPRI TR-105714 and TR-102134. Provide details of the specific changes to these documents after Revision 3. Include a justification as to how the adoption of the later revisions impact the effectiveness of the AMP to manage aging effects.	The Revision 4 changes to TR-105714 consider the most recent operating experience and laboratory data. It reflects increased emphasis on plant-specific optimization of primary water chemistry to address individual plant circumstances and the impact of the Nuclear Energy Institute (NEI) steam generator initiative, NEI 97-06, which requires utilities to meet the intent of the EPRI guidelines. TR-105714, Rev. 5 clearly distinguishes between prescriptive requirements and non-prescriptive guidance. Revision 4 of TR-102134 was issued in November 1996 and provided an increased depth of detail regarding the corrosion mechanisms affecting steam generators and the balance of plant, and also provided additional guidance on how to integrate these and other concerns into the plant-specific optimization process. Revision 5 provides additional details regarding plant-specific optimization and clarifies which portions of the EPRI guidelines are mandatory under NEI 97-06. Revision 6 provided further details regarding how to best integrate these guidelines into a plant-specific chemistry program while still ensuring compliance with NEI 97-06 and NEI 03-08. IPEC and other utilities provide input as well as review the recommendations and changes made to EPRI guidelines. Based on guideline review against the current chemistry program, manufacturer recommendations, and associated station documents, changes are made to chemistry controlling procedures which are subject to the safety review process (10 CFR 50.59 process). Consequently, the Water Chemistry Control – Primary and Secondary Program based on current EPRI guidelines is made more effective at managing aging effects through proactive implementation of later revisions of the EPRI guidelines.
99	AMP B.1.41-2 (Water Chemistry-Primary & Secondary) The LRA Section B.1.41 lists an enhancement to Attribute 3, Parameters Monitored or Inspected	Consistent with EPRI TR-105714, Rev. 5 recommendations, IP3 currently monitors RWST sulfates monthly with a limit of < 150 ppb. IP2 has not incorporated this recommendation and an enhancement is required. Thus, the enhancement does not apply to IP3.

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	and Attribute 6, Acceptance Criteria, which requires revision of appropriate IP2 procedures to test sulfates monthly in the RWST with a limit of < 150 ppb. Why is this enhancement only applicable to IP2 and does not apply to IP3?	
100	AMP B.1.41-3 (Water Chemistry-Primary & Secondary) The LRA Section B.1.41, under Operating Experience, states that a QA audit of the primary and secondary plant chemistry program was conducted in August 2003 and this audit noted that monitoring and processing requirements for primary and secondary water chemistry complied with both IP2 and IP3 technical specifications, implementing procedures, and the IP3 Technical Requirements Manual (TRM). (a) Why is there no statement about compliance with IP2 Technical Requirements Manual? (b) The specific QA audit described above was in August 2003. How frequently are these QA audits performed?	a) While chemistry requirements are currently included in the IP2 Technical Requirements Manual, the QA audit in August 2003 was performed during the improved technical specification project and updating the TRM for both units. At the time of the audit, the IP2 TRM was not updated with chemistry requirements. b) QA audits of the chemistry department are performed every 2 years. An additional audit was performed in 2006 to adjust the two year cycle to even number years for scheduling purposes. Both 2005 and 2006 audit reports were provided during the audit.
103	Please provide 2006 Fire Water System Flow Test.	2006 Fire Water System Flow Test provided.
104	Provide Approval Package for SA0-703 rev 25.	Approval package per EN-DC-128 provided for SAO-703, rev 25.
105	Are the IP3 foam tanks required for compliance with 10 CFR 50.48. Why is the enhancement for foam tank inspection only applicable to IP3?	The foam tanks for IP2 and IP3 are not required to comply with the requirements of 10 CFR 50.48. The IP3 foam tanks (FOAM TANK 1/2/3/4) were conservatively included as components subject to aging management review during consideration of non-safety related components that may affect safety related components. Further review revealed that since the tanks are located on concrete slabs on lower elevations of the turbine buildings and are not pressurized, failure of the foam tanks would not affect safety related equipment. Therefore, neither the IP2 nor the IP3 foam tanks (or their drain line components) are subject to aging management review. Consequently, the enhancement requiring internal inspection of the IP3 foam tanks is not required. The LRA will be revised to delete the enhancement specifying internal inspection of the IP3 foam tanks in Sections A.3.1.13 and B.1.14. LRA table 3.3.2-19-11-IP2 and 3.3.2-19-20-IP3 will be revised to remove line items for components with the environment of fire protection foam. Clarification to be incorporated into the LRA.
106	The enhancement for element 4 of the Fire Protection Program that applies to sprinkler head requirements per NFPA 25 states the nozzles are inspected. NFPA requires the nozzle to be tested or replaced. Inspections do not meet the Code requirements.	The Fire Water System Program enhancement to Element 4 will be revised to more clearly reflect the requirements of NFPA as follows. Replace the beginning of the first sentence which states "A sample of sprinkler heads required for 10 CFR 50.48 will be inspected using guidance of NFPA..." with " Sprinkler heads required for 10 CFR 50.48 will be replaced or a sample tested using guidance of NFPA...". Clarification to be incorporated into the LRA.
107	B.1.1: The gas turbine fuel storage tanks were repaired following the discovery of pitting in April 2002 using a weld overlay. What was the regulatory basis for this repair (e.g., Code repair, approved code case, relief request) and how will it be handled for the period of extended operation?	This repair of pitting in the tank bottom was made in accordance with API Standard 653 second edition, December 1999 "Tank Inspection, Repair, Alteration, and Reconstruction". This is a nonsafety-related tank. The GT 2/3 fuel oil storage tank has a repetitive task for an internal inspection, and UT cleaning that is scheduled on a 10 year frequency as described in the Above Ground Steel Tanks Program.
108	B.1.2: Does IP2 and IP3 have a bolting expert as recommended in the EPRI documents?	EPRI TR-104213, Bolted Joint Maintenance & Applications Guide, recommends providing an on-site bolting coordinator who has the technical ability and authority to focus on both programmatic issues and day-to-day resolution of problems. IPEC Maintenance provides the functions of the bolting coordinator consistent with the

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		guidance of EPRI TR-104213.
109	B.1.5: Have you observed boric acid leakage from Conoseal flanges?	Both IP2 and IP3 have experienced periodic Conoseal leakage during the past few cycles of operation. The most recent leaks occurred at penetration #95 during the current IP2 fuel cycle while the most recent leak at IP3 was detected during the Spring 07 refueling outage. As a result of these leaks, both IP2 and IP3 have implemented a modification to the Conoseal flanges to minimize the probability of future leakage. All of the recent leaks (with the exception of the current leak at penetration #95) have been eliminated and the affected areas of the reactor vessel head have been cleaned and examined for signs of material degradation. None of these leaks have resulted in any detectable degradation of either (IP2 and IP3) reactor vessel head.
110	B.1.6: Do you have any buried tanks in scope for license renewal? If so, please identify them. Has IP2 or IP3 had to replace any buried piping or had to replace or repair any sections of buried pipe?	The following tanks are buried and in scope for license renewal and included in the Buried Piping and Tanks Inspection Program. IP2 Fuel Oil Storage Tanks (21/22/23 FOST) GT1 Fuel Oil Storage North and South Storage Tanks IP2 Security Diesel Fuel Tank IP3 Appendix R Fuel Oil Storage Tank (EDG-33-FO-STNK) IP3 Security Propane Fuel Tanks (2 of them) IP3 Fuel Oil Storage tanks (EDG-31/32/33-FO-STNK) A review of site condition reports back to 2000 revealed that there have been two underground piping leaks that occurred on the auxiliary steam supply cross connect line between Unit 2 and Unit 3. The first leak occurred in 2002 and CR-IP3-2002-04267 was written for this leak. The leak was repaired via the work control process. *The second leak occurred in April 2007 and is documented in* CR-IP3-2007-01852. This line has been excavated and replaced. The cause of the failure was determined to be advanced corrosion of the pipe due to moisture intrusion. This was caused by the pipe coating breaking down and insulation that was not sufficient for the task. After replacement, the pipe was reinsulated using a special high temperature application moisture resistant material, that was designed to prevent this type of corrosion in the future. This piping is nonsafety-related and not in the scope of license renewal. Copies of the condition reports were provided. No other buried piping repair or replacement was identified during review of operating experience.
111	Provide Fire Protection System Impairment Summary.	Provided the fire protection system impairment summary as of 6-10-07.
123	AMP B.1.23 (Non-EQ Inaccessible Medium-Voltage Cable) Why are cables for service water pump motors not included in the B.1.23 AMP?	The Indian Point service water cables are safety-related, but are 480 VAC. As stated in the Sandia report 96-0344, DOE Cable AMG, water treeing is a degradation phenomenon that has been documented for medium-voltage electrical cable with certain extruded polyethylene insulations and EPR insulations. Water treeing has historically been more prevalent in higher voltage cables; proportionately few occurrences have been noted for cables operated below 15 kV. This is likely due to the comparatively high electric field density and voltage gradient required for significant treeing to occur. However, water treeing in medium-voltage cable operated below 15 kV has been documented. The formation and growth of trees varies directly with operating voltage; treeing is much less severe in 4-kV cables than those operated at 13 or 33 kV. Due to the low dielectric stress, water trees do not occur in low-voltage cables. Jackets and semiconducting shields may substantially reduce the ingress of moisture and ion migration, thereby reducing the rate of tree formation and propagation. New materials using ion scavengers may be effective at further reducing water tree growth. The DOE AMG typically defines medium voltage as 4 kV to 13.8 kV, but conservatively defines the lower value as 2 kV. NUREG-1801 and the license renewal electrical handbook uses the lower value of 2 kV. The longer a medium voltage cable is energized, the greater the likelihood that moisture will affect the service life of the cable. Degradation of insulation materials due to "water treeing" is a potential aging mechanism for underground medium voltage cables that are energized greater than 25% of the time and subject to moisture. Cables in underground duct banks or conduits are considered underground cables subject to moisture for the Indian Point IPA. All of the Indian Point safety-related power cables are 480 VAC, so there are no medium voltage circuits that are safety-related. The 480 VAC cables are not subject to water treeing; therefore, there are no aging effects requiring management by the Non-EQ Inaccessible Medium-Voltage Cable AMP (B.1.23). The cables included in

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		the B.1.23 AMP are in scope for 10 CFR 54.4(a)(3)
124	AMP B.1.20 (Metal-Enclosed Bus Inspection) The LRA program description only discusses visual inspections, but the enhancements to the existing plant program discuss visually inspecting bolted connections every 5 years, or every 10 years if using thermography. In site document for the AMP evaluation, items 3(b), 4(b), and 6(b) discuss only using visual inspections. The existing site procedure for the 480 VAC bus uses micro-ohm checks. Why is only visual inspection discussed? Why are the other methods in GALL XI.E4 not discussed? Provide additional discussion for the other inspection methods addressed in GALL, or provide the basis for not including the other methods.	As indicated in LRA Section B.1.20, the "Metal-Enclosed Bus Inspection Program" is consistent with the inspection methods described in NUREG-1801. The program description in LRA Section B.1.20 will be clarified to describe the alternate tests and inspections discussed in NUREG-1801, Section XI.E4. Visual inspections will continue to be used for bolted connections as appropriate. The site AMP evaluation report will also be clarified as discussed for LRA B.1.20. The program description, and Items 4(b), and 6(b) will be modified to address the inspection methods besides visual that are discussed in NUREG-1801, Section XI.E4. Item 3(b) does not require a change, since this item is consistent with NUREG-1801. The inspection methods used in the existing site procedures will be reflected in the site AMP evaluation report. LRA Section B.1.20, Metal Enclosed Bus Inspection, Program Description, second paragraph, and the enhancements are revised as follows. Program Description Inspections of the metal enclosed bus (MEB) include the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. A sample of the accessible bolted connections will be inspected for loose connections. The bus enclosure assemblies will be inspected for loss of material and elastomer degradation. This program will be used instead of the Structures Monitoring Program for external surfaces of the bus enclosure assemblies. The internal portions of the MEB will be inspected for foreign debris, excessive dust buildup, and evidence of moisture intrusion. The bus insulation or insulators are inspected for degradation leading to reduced insulation resistance (IR). The bus insulation will be inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The internal bus supports or insulators will be inspected for structural integrity and signs of cracks and corrosion. These inspections include visual inspections, as well as quantitative measurements, such as thermography or connection resistance measurements, as required. Enhancements Attributes Affected: 3. Parameters Monitored or Inspected; 4. Detection of Aging Effects; 6. Acceptance Criteria Revise appropriate procedures 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. Attributes Affected: 4. Detection of Aging Effects Revise appropriate procedures to inspect bolted connections at least once every five years if only 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. LRA Sections A.2.1.19 and A.3.1.19, Metal Enclosed Bus Inspection Program, second paragraph, is revised as follows. Inspections of the metal enclosed bus (MEB) include the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. A sample of the accessible bolted connections will be inspected for loose connections. The bus enclosure assemblies will be inspected for loss of material and elastomer degradation. This program will be used instead of the Structures Monitoring Program for external surfaces of the bus enclosure assemblies. The internal portions of the MEB will be inspected for foreign debris, excessive dust buildup, and evidence of moisture intrusion. The bus insulation or insulators are inspected for degradation leading to reduced insulation resistance (IR). These inspections include visual inspections, as well as quantitative measurements, such as thermography or connection resistance measurements, as required. LRA Sections A.2.1.19 and A.3.1.19, Metal Enclosed Bus Inspection Program, third paragraph, second bullet is revised as follows. Revise appropriate procedures to inspect bolted connections at least once every five years if only performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements.

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		Clarification to be incorporated into the LRA.
125	AMP B.1.20 (Metal-Enclosed Bus Inspection) The site document for the AMP operating experience discusses items found in the bus IP3 480 V Switchgear. Provide additional details for this incident and explain why this incident was not detrimental to the System function.	The site operating experience review report listed operating experience obtained from the condition report system. The issue at IP2 in 2006 was found during the performance of the non-safety related 6.9 kV Bus 4 PM. Degradation was found on the load side of the heater drain pump motor cables. The damage to the cable jacket/insulation was due to vibration of a support plate, and the cable degradation was repaired. The degradation was minimal, and the function of this cable was not affected. This CR was associated with 6.9 kV switchgear, which is not associated with the metal enclosed bus. This OE is an example of a design issue or a maintenance issue. The issue at IP3 in 2003 was found during the performance of the safety-related 480 V Bus 5A PM. A switchgear separation barrier plate was found lying loose in the back of the switchgear cabinet. Also, a piece of cable approximately 10 inches long was found lying in the bottom of the switchgear cabinet. These were maintenance issues and the actions were to remove the section of cable, and attach the plate based on the design configuration.
126	Please provide copies of recent self assessments of the Inservice Inspection Program.	Provided copies of QA-08-2005-IP-1, "IPEC Unit 3 Engineering Programs Audit," 5/5/2005; LO-WPOLO-2004-00051, "ISI Snapshot Assessment for IPEC," 10/19/2004; and LO-WPOLO-2005-00046, "ISI Snapshot Assessment for IP2," 04/28/2005.
127	B.1.9: In section 4.5 of LRD07 under program description it states that thickness measurements of storage tank bottom surfaces verify degradation is not occurring. This implies that measurements are being currently being performed. Does this need to be revised to say after enhancements are completed?	The program description provides a general description of what the program will do after all enhancements are implemented. This is in accordance with NEI 95-10 Appendix D for application format and NUREG-1800 Table 3.3-2 which provides guidance for what a program description should include. Enhancements and exceptions are not discussed in this section of the document but are presented in each of the elements that have the exceptions and enhancements.
128	B.1.9: In section 4.5 of LRD07 section B.2.a GALL says periodic draining of water collected at the bottom of tanks minimizes amount of water. How is this addressed in B.1.9? What procedures perform this draining or water removal at IPEC?	Procedure 0-CY-1810 covers the monitoring of all diesel fuel oil on site and has a specification of "none detectable" for the tank bottom sample. When water has been detected, it has been removed in the past by direction of a supervisor. The sampler itself has been utilized in the past to remove water while obtaining a sample. Chemistry procedure 0-CY-3340 OPERATION OF THE GORMAN-RUPP TANKLEENOR could be utilized if larger amounts of water were encountered. 0-CY-1810 will be enhanced to include direction to remove water from the tank bottom if detected. In addition the revision will direct the sample be taken near the tank bottom for water detection. Information to be incorporated into the LRA.
129	B.1.9: In section 4.5 of LRD07 section B.2.a in the section that discusses sampling of the fuel oil tanks near the bottom to determine water content it refers to procedure 0-CY-1500 attachment 4. This procedure does not appear to discuss sampling near the bottom of the tanks. Why is this procedure a reference and if so should it discuss sampling location?	Attachments 2 and 4 provide the location of the sample points for fuel oil storage components. It includes the sample locations for the following fuel oil storage tanks but does not specifically state the samples are to be taken on the bottom of the tanks: IP2 EDG Day tanks (21/22/23), IP2 Fire protection diesel fuel tank, GT1 Fuel Oil South and North tanks, GT2&3 Fuel Oil Tank, IP3 EDG fuel oil day tanks (31/32/33), IP3 Fire Pump Fuel oil tank , IP2 Underground Emergency Diesel Fuel Oil Tanks and the IP3 Appendix R Fuel Oil Day tank. Attachment 1 of procedure 0-CY-1810 includes a requirement for a bottom sample of the IP2 and IP3 EDG bulk fuel oil storage tanks (21/22/23/31/32/33) and the GT1, 2, and 3 storage tanks since procedure 0-CY-1500 lists a composite sample and not a specific sampling point. It doesn't however specify that the remaining tanks sampling is to be taken near the bottom of the tank. Appropriate procedures will be revised to specify sampling tanks in this program near the bottom of the tank. This requires an ehancement to the Diesel Fuel Monitoring program B.1.9. Information to be incorporated into the LRA
130	B.1.9: In section 4.5 of LRD07 section B.3.a GALL says ASTM D1796 and D2709 are used for determination of water and sediment. IPEC only uses ASTM D1796 and not D2709. Why is this	As stated in the last three sentences of B.3.b of section 4.5 of IP-RPT-06-LRD-07, ASTM standards D1796 and D2709 are standards for the determination of water and sediment for different viscosities of fuel oil. ASTM standard D1796 is the appropriate standard for the ASTM-2D fuel oil used at IPEC. ASTM standard D2709

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	acceptable?	(water and sediment by centrifuge for lower viscosities) is not applicable for the fuel oil used at IPEC.
131	B.1.9: In section 4.5 of LRD07 section B.6.a GALL says ASTM D 6217 and modified D2276 are used. IPEC only uses ASTM D2276 and not D6217. Why is this acceptable?	It is acceptable to not use ASTM D6217 because use of ASTM D2276 is a more conservative method to measure the same parameter. ASTM D6217 is a laboratory method for middle distillate fuel particulate distillation. This method uses a smaller volume of sample passing over the filter membrane. As referenced in ASTM D6217, " Test Method D5452 and its predecessor Test Method D2276 were developed for aviation fuels and used 1 gal or 5 L of fuel sample. Using 1 gal of a middle distillate fuel, which can contain greater particulate levels, often required excessive time to complete the filtration. The D6217 test method used about a quarter of the volume used in the D2276 method." Both of the methods use the same filter size of .8 microns. The difference in filtering a larger volume for a longer time using the ASTM D-2276 method is actually more conservative. LRA Section B.1.9, second paragraph of exception to Element 6 will be revised as follows. For determination of particulates, NUREG-1801 recommends use of modified ASTM Standards D2276 Method A and D6217. Determination of particulates is according to ASTM Standard D2276. LRA Section B.1.9, exception note 4, will be revised as follows. Determination of particulates is according to ASTM Standard D2276 which conducts particulate analysis using a 0.8 micron filter, rather than the 3.0 micron filter specified in NUREG-1801. Use of a filter with a smaller pore size results in a larger sample of particulates since smaller particles are retained. Thus, use of a 0.8 micron filter is more conservative than use of the 3.0 micron filter specified in NUREG-1801. ASTM D6217 applies to middle distillate fuel using a smaller volume of sample passing over the 0.8 micron filter. Since ASTM D2276 determines particulates with a larger volume passing through the filter for a longer time than the D6217 method, use of D2276 only is more conservative. Clarification to be incorporated into the LRA.
132	B.1.9: Procedure 2-CY-1560 for IP2 has as section 4.5 that has a step to add chemicals to the fuel oil storage tanks if determined necessary by Chemistry. There does not appear to be a similar step in any IP3 procedure but there is a procedure 3-CY-2615 for adding chemicals to fuel oil tanks. Does this exist in an IP3 procedure and if not why the difference?	There is not an IP3 procedure directing when to add biocide to the IP3 fuel oil tanks. Prior to integration of the units, the procedure already existed at Unit 2. Procedure integration focused on the type of chemicals to be added; it did not explicitly evaluate the method or timing of the chemical addition. An enhancement will be added to combine the direction from 3-CY-2615 and 2-CY-1560 into a 0-CY series procedure for the addition of chemicals including biocide on both units when the presence of biological activity is confirmed. Information to be incorporated into the LRA.
133	B.1.20: (Metal Enclosed Bus) The site document for the AMP evaluation references a site procedure for performing 480VAC metal enclosed bus inspections. One of the steps discusses "re-torquing" connections. Why is re-torquing acceptable?	The aging management program evaluation report for the "Metal Enclosed Bus Inspection Program, which is described in LRA Section B.1.20, does not require "re-torquing" connections. The plant staff acknowledged that the practice of "re-torquing" connections is not a good practice, and was not intended to be performed. "Re-torquing" connections is not recommended in EPRI documents for phase bus maintenance and bolted connection maintenance. The plant will process a change to the site procedure to remove the reference to "re-torquing" connections.
148	Service Water Integrity Inspector requested a copy of EN-DC-184 referred to in SEP-SW-001 in section 1.1	At the time SEP-SW-001 was being developed, a corporate procedure (EN-DC-184) was also being drafted to apply to all 10 Entergy plants. EN-DC-184 would have included all the requirements that SEP-SW-001 presently provides. However, some plants had issues with the corporate procedure, and it has not yet been finalized or approved. It should be noted that the corporate procedure drafted at the time SEP-SW-001 was originally issued would not have added any additional requirements to the IPEC SW program, such that SEP-SW-001 was and is being correctly and effectively implemented at this time. Procedure SEP-SW-001 states that the site procedure aligns with the corporate procedure EN-DC-184. This is an incorrect statement since there is no corporate procedure for service water programs. Since there is no impact on the site program from this discrepancy, this error will be corrected during the next procedure review and revision. A copy of rev. 1 to SEP-SW-001 and the IPEC response letters to Generic Letter 89-13 were provided to the inspector.
149	Impairment summary for fire protection systems (6-10-2007) indicates that the "Utility tunnel HP fire header has less than minimum wall thickness and	The utility tunnel HP fire header is presently isolated as the result of discovery of piping section(s) that have degraded below minimum allowable wall thickness. The loop segmentation capabilities of the HP fire water loop enable the required fire

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	header isolation". What is the relationship to the HP fire water system and the root cause? (See enhancement regarding wall thickness evaluations) (See B.1.14 Operation Experience section RE: No evidence of loss)	protection water supplies to safety-related and safe-shutdown related plant areas to be maintained, despite the isolation of the utility tunnel header. The degradation of carbon steel piping within the utility tunnel (city water and fire protection headers) was determined to be caused by chronic in-leakage of ground water into the tunnel, causing external corrosion of the city water and fire protection piping. Engineering evaluations have been developed and work orders planned to address the cause by sealing the leaking penetrations/openings into the utility tunnel, thereby minimizing further water intrusion and contact with piping surfaces. In addition, the city water piping will be encapsulated with a proprietary piping wrap and coating restoration system that will restore the structural and hydraulic integrity of the city water piping, and provide an exterior surface that will be resistant to corrosion. A similar modification is being evaluated for restoration and protection of the Fire Protection piping in the utility tunnel. The sealing of the utility tunnel wall and ceiling penetrations as described above will eliminate the water intrusion and source of the exterior corrosion. The installation of the modification to seal the utility tunnel wall and ceiling penetrations is scheduled for completion during 2007. The Fire Water System Program manages aging effects for components exposed to treated water (fire water) on internal surfaces. The external surface of fire water components is managed by the External Surfaces Monitoring program. Since the loss of material described in this operating experience was on the external surface and caused by water intrusion, this operating experience is not applicable for the Fire Water System Program.
150	The exception to NUREG-1801 for B.1.13 regarding the frequency of functional testing of Halon (IP2) and CO2 (IP3) from 6-months to 18 and 24 months respectively does not provide the station/system specific operating history. What is the engineering basis and justification for these specific systems?	The current functional testing frequencies of the IP2 cable spreading room Halon system and the IP3 cable spreading room, IP3 480V switchgear room and IP3 Diesel Generator Building CO2 systems is as follows: IP2 cable spreading room Halon system - once per 18 months IP3 cable spreading room, IP3 480V switchgear room and IP3 Diesel generator building CO2 systems - once per 24 months with the exercising of fire dampers which form the boundary of the protected enclosures at once per 12 months. A review of past performed functional testing of these systems has indicated no adverse indications of material degradation that requires adjustment of the testing frequencies. (ref. PT-EM19, 3-PT-2Y004 and 3-PT-2Y005). The condition reporting database was similarly reviewed and revealed no adverse indications of material degradation.
151	What is the original licensing basis for the functional testing frequency of CO2 and Halon systems at IP2 and IP3?	The original licensing basis for the functional testing frequency of CO2 and Halon systems at IP2 and IP3 are as follows: IP2 The cable spreading room Halon system was installed as part of the plant modifications to improve the fire protection program resulting from reviews against BTP APCSB 9.5-1, Appendix A. Limiting conditions for operation and surveillance requirement were subsequently developed for this system and approved by the NRC under Amendment 64 to the FOL (ref. SER dated October 31, 1980). The functional test frequency was once per 18 months. This frequency is currently maintained in the administrative procedure SAO-703. IP3 The cable spreading room, 480V switchgear room and Diesel generator building CO2 systems were installed as part of the plant modifications to improve the fire protection program resulting from reviews against BTP APCSB 9.5-1, Appendix A. Limiting conditions for operation and surveillance requirement were subsequently developed for these systems and approved by the NRC under Amendment 45 to the FOL (ref. SER dated November 18, 1982). The functional test frequency was once per 18 months. A change to the functional testing frequency for these systems was subsequently proposed and approved by the NRC under Amendment 146 to the FOL (ref. SER dated April 20, 1994) to accommodate operation within a 24 month operating cycle.

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		The functional test frequency was changed to once per 24 months with the exercising of fire dampers which form the boundary of the protected enclosures at once per 12 months. These frequencies are currently maintained in the IP3 TRM (Ref. TRO 3.7.A.7
152	What is the justification for excluding the firewater jockey/ maintenance pumps from the scope of the HP fire water systems (B.1.14)? These are not identified in : SAO-703, rev25 (IP2) A.1 Section 3.7.A.1.7 and 3.7.A.1.8 of the IP3 TRM AP-64.1 Rev. 2 Appendix R SSCs	The fire water jockey/maintenance pumps support standby operation of the fire water system and are conservatively included in the scope of license renewal and subject to aging management review. The Fire Water System Program manages component aging effects. However, the jockey/maintenance pumps are not required for operation of the fire water system to comply with 10 CFR 50.48 and Appendix R. Therefore, prescribed testing per SAO-703, TRM and AP-64.1 is not required.
153	A "cross-connect" of the HP fire water system exists between Units 1, 2, and 3 individual fire water supply systems. Has credit been taken for the use of this capability per the CLB? (B.1.14)	IP2 and IP3 maintain independent fire protection systems and the "cross connect" is not considered for compliance with IP2 or IP3 fire protection requirements.
154	B.1.11 (External Surfaces Monitoring) Under attribute "Parameters Monitored and Inspected", examples of parameters inspected are provided and a reference is made to the systems walkdown procedure attachment 9.1. The guidelines in the attachment do not appear to cover attributes of coating degradaton and corrosion/material wastage. Clarify if these attributes are reviewed during system walkdowns. It is noted that the enhancement will revise guidance documents to require periodic inspection of systems in scope and subjet to an AMR. Will the revision include inclusion of these attributes?	Attachment 9.1 includes a line item of paint and preservation which would encompass coating degradation and corrosion/material wastage since if the paint is intact and the equipment properly preserved coating degradation and corrosion/material wastage would not be present. Attachment 9.1 also includes a statement at the beginning that the guidelines are not all inclusive. This is also documented in attachment 9.2 which is a checklist that identifies paint and preservation as potential items of concern. As stated in section 1.0 of EN-DC-178 a system walkdown is a detailed look at system material condition which would include the attributes of coating degradation and corrosion/material wastage regardless of it being specifically identified as an inspection item.
155	B.1.11 (External Surfaces Monitoring) Under the attribute "Detection of Aging Effects" a list of components and environments is given for those AMMs where visual inspection of the external surfaces is credited for internal surfaces. In two cases, the internal environment is given as indoor air, but the external environment is given as air-indoor or air-outdoor. Explain why this is acceptable?	The use of the condition of external surfaces to provide an indication of the condition of internal surfaces is acceptable when the external environment is outdoor air because the external environment is much more aggressive. Therefore, if visual inspections of the external surface are not experiencing loss of material, the internal surface is assured to be in good condition due to the milder internal environment.
156	B.1.15 (FAC): The program description provided for AMP B.1.15 in the LRA states that the program is based on the guiddelins of EPRI NSAC-202L-R2. The review of Indian Point Procedure EN-DC-315, rev. 0 Flow Accelerated Corrosion Program provided during the site audit, references "latest" revison of this document which is revision 3. Since the guidelines provided in two revisions of NSAC-202L are different, address which hrevison of the document is applicable to Indian Point FAC Program. If Indian Point utilizes Rev. 3 of the NSAC document, the LRA should list this as an exception and include a justification for the use of the later revision to establish consistency with GALL Report.	Indian Point utilizes Revision 3 of NSAC 202L. As indicated in NSAC 202L, Revision 3, the new revision of EPRI guidelines incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that became available since Revision 2 was published. The updated recommendations refine and enhance those of previous revisions without contradicting existing plant FAC programs. An exception to GALL was not taken since implementing the elements of Revision 3 guidelines did not create program deviations from the guidelines in Revision 2 and the requirements specified in GALL are being met with Revision 3 of NSAC-202L. A review of the FAC program elements affected by Revision 3 changes is provided as follows showing the changes had minimal impact on the program. Element (1), Scope of Program – The differences of Section 4.2, Identifying Susceptible Systems, between Revision 2 and Revision 3 are mostly editorial. The guidance of prioritizing the system for evaluation in Section 4.2.3 of Revision 2 is addressed in Section 4.9 of Revision 3. Section 4.4, Selecting and Scheduling Components for Inspection, of Revision 2 was re-organized in Revision 3. Sample selection for modeled lines and non-modeled lines of Revision 2 was enhanced with more clarification and more details in Revision 3. Guidance for using plant experience and industry experience in selecting inspection locations was added in Revision 3. The basis for sample expansion was clarified in Revision 3. Instead of dividing into selection of initial inspection and follow-up inspections in Revision 2, the guidance in Revision 3 is provided for a given outage including the recommendations for locations of re-inspection. This is more compatible with the schedule of the implementation of FAC program during outages. Element (4), Detection of Aging Effects – Clarification of the inspection techniques of UT and RT was added in Section 4.5.1 of Revision 3. There are no changes of the

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		guidance for UT grid. Appendix B was added in Revision 3 to provide guidance for inspection of vessels and tanks. This is beyond the level of detail provided in Revision 2 and in the GALL report. The guidance for inspection of small-bore piping in Appendix A of Revision 2 and of Revision 3 are essentially identical. The guidance for inspection of valves, orifices, and equipment nozzles was enhanced in Section 4.5.2 of Revision 3. Also, Section 4.5.4 was added for use of RT to inspect large-bore piping, Section 4.5.5 was added for inspection of turbine cross-around piping, and Section 4.5.6 was added for inspection of valves. Clarification to be incorporated into the LRA.
157	Fire Barriers What is the current frequency of inspection for fire barrier penetrations and what is the % sample to be inspected?	All accessible fire barrier penetration seals are visually inspected at least once every seven operating cycles (approximately 15% per 24 months operating cycle). During each inspection interval, at least 10% of each type of seal is inspected.
158	Fire Barriers Fire separation barrier inspections (2-PI-Q001 Rev. 8) acceptance criteria does not include a specific failure mode of HEMYC fire barrier wrap identified in GL 2006-03. Specifically the potential shrinkage of the outer layer fabric (Refrasil) that could expose the interior layors of Kawool . Is this guidance (GL 2006-03) incorporated into the barrier inspection program and specifically where?	The failure mode cited in Generic Letter 2006-03 specifically the potential shrinkage of the outer covering, exposing the interior surfaces or layers to the fire, relate to the performance and response of a Hemyc fire barrier wrap under fire conditions which were installed in accordance with vendor requirements. These requirements were similarly used during the installation of the Hemyc fire barrier wrap at IP2 and IP3. Periodic test 2-PI-Q001 ensures through a visual inspection that the material condition of the wrap is satisfactory (i.e., the wrap is not missing, punctured or torn, the wrap is not oil soaked or shows evidence of other chemical contamination and that it is properly banded as required), thereby consistent with the initial pre-fire condition.
159	B.1.23 a) Item 3(b) of the site AMP evaluation document references an EPRI document instead of listing examples of types of tests that could be performed similar to those provided in GALL. Provide information so a determination can be made for consistency of the EPRI document and the GALL example programs. B) Item 4(b) of the site AMP evaluation document states that an engineering evaluation will be perfomed to determine the proper frequency for manhole inspection. Provide information for how this will use OE to justify the frequency.	LRA Section B.1.23 and the site AMP evaluation document state this program is consistent with NUREG-1801, XI.E3 without exceptions or enhancements. a) The AMP evaluation document for the Non-EQ Inaccessible Medium-Voltage Cable, Item 3(b) will be clarified to provide examples of tests. Current "The specific type of test performed will be determined prior to the initial test. The test will be a proven test for detecting deterioration of the insulation system due to wetting as described in EPRI TR-103834-P1-2 or other testing that is state-of-the-art at the time the test is performed." Proposed The specific type of test performed will be determined prior to the initial test, and is to be a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed. b) The AMP evaluation document for the Non-EQ Inaccessible Medium-Voltage Cable, Item 4(b) will be modified to clarify the use of site OE for the frequency of manhole inspections. Current Inspections will be based on actual plant experience with water accumulation in manholes and the frequency of inspection will be adjusted based on the results of an engineering evaluation, but an inspection will occur at least once every two years, with the first inspection for license renewal occurring prior to the period of extended operation. Proposed Inspections will be based on actual plant experience with water accumulation in manholes. Based on water accumulation discovered during inspections, the frequency of inspection will be adjusted based on the results of corrective action process evaluations. The inspections will occur at least once every two years, with the first inspection for license renewal occurring prior to the period of extended operation
160	B.1.10 During the discussion of the EQ program with the Indian Point owner, the process of incorporating	In January 2006, during an EQ program enhancement project it was discovered that an IP3 EQ file did not identify or address qualifications of pigtail extension cables. A CR was initiated to capture EQ documentation deficiency, which was not an environmental qualification deficiency. The EQ program enhancement project was

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	OE into the program was discussed. Other than the information provided in the site OE report, is there any additional OE associated with effectiveness of the EQ program.	initiated to correct this type of historical discrepancy. The applicable test reports were obtained, and were evaluated. The applicable test reports met IP3's environmental parameter requirements, so these cables were considered qualified. Therefore, there was no operational concern. An extent of condition review was not required because of the EQ program enhancement project. In July 2004, it was identified that the EQ program replacements for AOV components and the AOV program replacements could be redundant. Some of the AOV components are EQ, but not all. It was identified there was an inconsistency in the philosophy for these repetitive tasks. Also, there was an inconsistency on which tasks were routed for EQ program review. To address the extent of condition, corrective actions were to review the AOV replacement scope to ensure all EQ components that will be replaced under the AOV program repetitive tasks are documented. To ensure that Indian Point EQ Program stays current with the industry and that the industry operating experience (OE) is addressed, participation in several industry based working and assessment groups is maintained. The industry groups are comprised of utility operators worldwide, but the majority are in the US and Canada. Many topics and issues relating to equipment qualification are currently being pursued by these groups. Specific issues include the NRC's EQ Task Action Plan (active interaction with the NRC staff, NEI and the Group), Cost-Saving Measures related to EQ activities (e.g., revised source term, file/documentation management, staffing), SOV qualification (generally and with respect to specific designs (extended qualified life valves (NS-2 Group-sponsored testing)), cable qualification (e.g., aging, submergence, and similarity), issues arising from ongoing NRC inspections, qualification of High Range Radiation Monitors, issues arising from ongoing NRC Routine, Team and Special inspections, qualification of specific equipment types (splices, penetrations, transmitters, etc.) as identified by the Group, and integration of equipment qualification considerations into license renewal. Participation in these organizations also provides a source of regulatory and reference documents, component information, engineering analyses, and materials data from many different manufacturers and utilities.
161	B.1.13 The RCP lube oil tanks collection system includes a passive flame arrestor(s) to prevent flashback. The RCP lube oil collection system is inspected every 24 months and every 31 days for inventory. (SAO-703 Rev. 25) (IP2/ 2-PT-R201) Is this component included in the scope of the fire protection program (AMR) due to credit provided to FP SSC's? (10 CFR 54.4(a)(3)) & 10 CFR 50.48)	The RCP oil collection system flame arrestors are subject to aging management review with aging effects managed by the Fire Protection Program. The flame arrestors are included in the component type "piping" in Table 3.3.2-12-IP2 and 3.3.2-12-IP3.
164	The enhancement to the Fatigue Monitoring Program on LRA page B-45 discusses steady state cycles while the enhancement in the Program basis document (LRD02) page 43 discusses both steady state cycles and feedwater cycles. Shouldn't the LRA include feedwater cycles?	Yes, the LRA should include feedwater cycles. Entergy will revise two places in the application. Page B-45 and page A-22 to clarify that feedwater cycles are included in the enhancement. Note that commitment #6 to make this enhancement already contains feedwater cycles. Clarification to be incorporated into the LRA.
165	B.1.26 Oil Analysis Provide a technical basis for the oil sampling frequency.	Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. Procedure EN-DC-335, "PM Bases Template", is based on EPRI PM bases documents TR-106857 volumes 1 thru 39 and TR-103147. Each template contains sections describing failure location and cause, progression of defration to fail, fault discovery, and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure. A copy of the template bases for medium voltage motors, low voltage motors, and horizontal pumps and procedure EN-DC-335 were provided during the audit. Clarification to be incorporated into the LRA.
166	B.1.26 Oil Analysis NUREG-1801 Acceptance Criteria for XI.M39 states that water and particulate concentration is determined in accordance with industry	The Oil Analysis Program is designed to function as a screening tool to help identify adverse lube oil conditions or trends. The screening process is supplemented with detailed analysis in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951 and ASTM D96. Water, particle concentration and viscosity

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	standards. What industry standards form the basis for acceptance criteria at IP2 and IP3?	acceptance criteria are based on industry standards supplemented by manufacturers' recommendations. Clarification to be incorporated into the LRA.
167	Diesel Fuel Monitoring Provide frequency at which biological activity and/or particulate contamination concentrations are monitored for each fuel oil storage tank in scope of license renewal. Include basis for each frequency. If an industry standard is referenced in your response, provide a copy of that standard. *(electronic version preferred if available)*	Response provided in the revised response to question 31.
168	Diesel fuel Monitoring Provide ASTM Special Technical Publication 1005 referenced in response to Q 34. (Electronic version perferred if available.)	Copy of publication provided
169	Diesel Fuel Monitoring Provide ASTM D975. (Electronic version preffered if available.)	Provided copy of 1985 version of standard.
170	Oil Analysis What is the technical bases for the oil analysis frequencies at IPEC.	Oil analysis frequencies for equipment at IPEC are based on Entergy Templates, which have technical bases justifications in the templates. Procedure EN-DC-335, "PM Bases Template", references EPRI PM bases TR-106857 Volume 1 thru 39 and EPRI guide for determining PM task intervals TR-103147 in developing this procedure. Each template has a failure location and cause, progression of defraction to fail, fault discovery and task objective. Each component type uses these subjects to conclude to a frequency to mitigate failure. A printout of the template bases for medium voltage motors, low voltage motors and horizontal pumps were provided to the inspector, along with procedure EN-DC-335. Clarification to be incorporated into the LRA.
171	Please include a statement about inspection techniques utilized to the description of the One-Time Inspection Program in LRA Section B.1.27.	The One-Time Inspection program description in LRA Sections A.2.1.26, A.3.1.26 and B.1.27 will be clarified by addition of the following statement. "The inspections will be nondestructive examinations (including visual, ultrasonic, or surface techniques)." Clarification to be incorporated into the LRA.
172	In the list of One-Time Inspection Program activities, listed in the program description in Section B.1.27 of the LRA, some activities do not specify the types of components to be inspected. Please include the types of components to be inspected under these activities.	For several one-time inspection activities, the term "components" was used to describe piping, piping elements, and other components within the system that are of the material and environment to be inspected. For these one-time inspection activities, the application will be clarified by replacing " components" with "tanks, pump casings, piping, piping elements and components" as appropriate. Clarification to be incorporated into the LRA.
173	Please confirm in the commitment list and LRA Appendix A that new programs will be implemented consistent with the corresponding ten elements described in NUREG-1801. Additionally, the commitment must contain sufficient details on key elements to enable the staff to make a determination that the new AMP, when implemented as described, will be able to manage the aging effects. Further, the commitment shall provide an approximate schedule indicating when each of the new programs will be available for review by the staff.	The commitment list and LRA Appendix A will be clarified to state that new programs will be implemented consistent with the corresponding program described in NUREG-1801. The new programs are Buried Piping and Tanks Inspection, Non-EQ Inaccessible Medium-Voltage Cable, Non-EQ Instrumentation Circuits Test Review, Non-EQ Insulated Cables and Connections, One- Time Inspection, One-Time Inspection – Small Bore Piping, Selective Leaching, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS), and Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS). Clarification to be incorporated into the LRA. Commitment # 3, 15, 16, 17, 19, 20, 23, 26, and 27. Commitments incorporate by reference sufficient details on key elements to enable

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		the staff to make a determination that the new AMP, when implemented as described, will be able to manage the aging effects. Commitments include references to sections of Appendix B of the LRA that provide sufficient detail. The schedule for implementing new programs will be determined based on availability of fleet-wide resources and implementation commitment dates for various sites across the fleet. Programs will be available for review prior to the period of extended operation.
174	The program description provided for AMP B.1.28 in the LRA states that the One-Time Inspection – Small Bore Piping Program is a new program applicable to small bore ASME Code Class 1 piping less than 4 inches nominal pipe size (NPS 4 "), which includes pipe, fittings, and branch connections. The LRA also states that the Indian Point's new program will be consistent with NUREG-1801 Program XI.M35, One-Time Inspection of ASME Code Class 1 Small-Bore Piping. However, NUREG-1801, Section XI.M35, states that the program is applicable to small-bore ASME Code Class 1 piping and systems less than or equal to 4 inches nominal pipe size (i.e., sizes up to and including 4 inch size). If Indian Point intends to exclude 4" size from AMP B.1.28, this should be treated as an exception to GALL and a justification included in the LRA to establish consistency with the GALL report.	The NUREG-1801 Program Description for Program XI.M35 indicates that a One-Time Inspection Of ASME Code Class 1 Small-Bore Piping is needed because the ASME code does not include a volumetric examination of piping "less than or equal to NPS 4" to detect cracking resulting from thermal and mechanical loading or intergranular stress corrosion. However, according to ASME Code, a volumetric examination is already required for piping equal to NPS 4". Also, NUREG-1801 Item IV.C2-1 is the only PWR line item which applies the One-Time Inspection of ASME Code Class 1 Small Bore Piping Program (XI.M35). This line item is for Class 1 piping "less than NPS 4". Therefore, Entergy concludes that it is not the intent of GALL for Program XI.M35 to include NPS 4" pipe. Therefore, the IPEC One-Time Inspection – Small Bore Piping Program includes only small bore Class 1 piping < NPS 4", which is consistent with GALL.
175	Commitment letter NL-07039 for oil analysis states the oil analysis program will be enhanced to *formalize trending of preliminary oil screen results* as well as data provided from independent laboratories. The FSAR Supplement A.2.1.25 for oil analysis states that appropriate procedures will be revised to formalize trending. The commitment letter and the FSAR Supplement should state the same answer.	LRA Sections A.2.1.25 for IP2, A.3.1.25 for IP3, and B.1.26 will be revised to agree with Commitment 18 listed in commitment letter NL-07039. The last two *enhancements listed in Section* A.2.1.25 *and the last two enhancements listed in* Section A.3.1.25 will be revised to read as follows. "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. Formalize trending of preliminary oil screening results as well as data provided from independent laboratories." *Clarification to be incorporated into the LRA.*
176	In the list of Periodic Surveillance and Preventive Maintenance Program activities, some activities do not specify the types of components to be inspected. Please clarify the types of components to be inspected in these activities. Also, some activities do not indicate whether the internal or external surfaces are to be inspected. Please clarify.	For several Periodic Surveillance and Preventive Maintenance Program activities, the term "components" was used to describe piping, piping elements, and other components within the system that are to be inspected. For these Periodic Surveillance and Preventive Maintenance Program activities, the application will be clarified by replacing "components" with "piping, piping elements and components." The LRA will be clarified to show that the internal surfaces of piping, piping elements, and components are inspected by the Periodic Surveillance and Preventive Maintenance Program for the following items shown in the program description of Section B.1.29. Recirculation pump cooler housing Station air containment penetration piping Portable blowers and flexible trunks stored for emergency ventilation use EDG exhaust gas piping EDG air intake and aftercooler EDG starting air EDG cooling water makeup IP2 fuel oil cooler IP3 Appendix R radiator, aftercooler, starting air, and crankcase exhaust Auxiliary feedwater Control room HVAC IP2 Nonsafety-related affecting safety-related River water service system Waste disposal system Water treatment plant IP3 Nonsafety-related affecting safety-related Chlorination system Circulating water system

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		EDG system Floor drain system Gaseous waste disposal system Instrument air system Liquid waste disposal system Nuclear equipment drain system River water system Station air system Secondary plant sampling system Clarification to be incorporated into the LRA.
277	B.1.16 (M37) Flux Thimble Tube Inspection: Provide the referenced documents 5-222: IP-DSE-01-058 5-224: IP-RPT-06-001824	Reports IP-DSE-01-058, Review of R11 RPV Thimble Tube Eddy Current Inspection Results, and IP-RPT-06-001824, Fourth Eddy Current Inspection of the Incore Thimble Tubes, were provided to the staff for onsite review.
278	B.1.18 (MI + 53): Is there one document which controls like activities critical in this AMP?	The ISI programs for IP2 and IP3 are controlled by Entergy common administrative procedure ENN-DC-120. Additionally, IPEC Section XI repairs, replacements, and modifications are controlled by station administrative procedure IP-SMM-DC-907. Both documents were provided to the staff for onsite review
279	B.1.30: 1. Check document which addreses the penetrative measures recommended in RG 1.65 2. Review documents summarizing results from past inspections.	RG 1.65, dated October 1973, identified material and inspection requirements for reactor vessel head studs. GALL identifies the RG 1.65 preventive measures of (1) avoiding the use of metal-plated stud bolting to prevent degradation due to corrosion or hydrogen embrittlement, and (2) to use manganese phosphate or other acceptable surface treatments and stable lubricants. IPEC utilizes a plasma bonding technique, not the metal plating process described in RG 1.65, on the studs. The plasma bonding process provides corrosion protection and lubrication for the studs which satisfy the preventive measures of RG 1.65. The plasma bonding process was evaluated by engineering request (ER-IP2-04-11531, ER-IP3-04-11231) to ensure acceptability. Material specification and fabrication aspects of RG 1.65 Items 1 and 2 are addressed in procurement activities for the purchase of replacement studs. PO number 4500515914 specifies ASME SA540, GR 24, Class 3 bolts consistent with the ASME specification in RG 1.65. All studs are examined in accordance with ASME Code requirements during each 10 year ISI interval such that sampling considerations are addressed. Recent ISI reactor head stud inspection results indicate that the ISI Program is adequately managing reactor head stud aging effects. These activities meet the intent of RG 1.65 with respect to procurement, manufacturing, inspection, and corrosion resistance. Copies of replacement stud purchase documentation were provided to the NRC for onsite review.
280	B.1.31 (MIIA) RVH Penetration Inspection Referenced documents 5-143 - NL-05-001 5-144 -- NL-05-044	Provided letters for onsite review
283	If during the inspection, the flaw or indication exceeds the acceptance criteria proved in Section XI, IWB-3400, does Indian Point evaluate the condition in accordance with Section XI paragraph IWB-3131 and perform extra examination per Section XI IWB-2430? Describe the process followed by IP to address such condition and which IP procedure includes these requirements.	As described in the LRA, the One-Time Inspection – Small Bore Piping Program will be implemented consistent with the program described in NUREG-1801 Section XI.M35. The acceptance criteria section for that program states, "If flaws or indications exceed the acceptance criteria of ASME Code, Section XI, Paragraph IWB-3400, they will be evaluated in accordance with ASME Code, Section XI, Paragraph IWB-3131, and additional examinations are performed in accordance with ASME Code, Section XI, Paragraph IWB-2430." The process is as described in ASME Section XI. Upon its implementation, activities of the One-Time Inspection – Small Bore Piping Program will be included in the ISI program plan.

ATTACHMENT 4 TO NL-07-153

AMR Database Report, Revision 0

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

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190	3.1-1 In LRA Tables 3.1.2-3 and 3.1.2-4, Entergy credits water chemistry control – primary and secondary AMP to manage fouling in SG and HX tubes in three line items for each IP unit. The LRA marks generic note H for these line items for tubes exposed to treated or treated borated water, indicating that there is no NUREG-1801 (or GALL) line item for the component, material and environment combination. Describe how the water chemistry control – primary and secondary AMP will prevent fouling in SG and HX tubes in the RCS and what method(s) would evaluate that this aging effect is not occurring in these components and thus, the effectiveness of the water chemistry control – primary and secondary AMP.	Fouling of heat exchanger tubes occurs due to a lack of effective water chemistry control on the tube surfaces. Maintaining the reactor coolant and feedwater chemistry in accordance with the Water Chemistry Control – Primary and Secondary Program minimizes the fouling of the heat exchanger surfaces. As part of the Water Chemistry Control – Primary and Secondary Program, the One-Time Inspection Program employs inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – Primary and Secondary Program has been effective at managing fouling. For the line items in Tables 3.1.2-3 and 3.1.2-4 that credit Water Chemistry Control – Primary and Secondary as the AMP to manage fouling in SG and HX tubes, a plant-specific Note 104 will be included to clarify that the One-Time Inspection Program will verify effectiveness of the Water Chemistry Control- Primary and Secondary Program. Clarification to be incorporated into the LRA.
191	3.1-2 a) In LRA Section 3.1.2.2.1 and the discussion in LRA Table 3.1.1, item number 3.1.1-1, Entergy indicates that the reactor vessels at IP2/3 are not supported by support skirts and therefore, cumulative fatigue damage (as a TLAA) for support skirts is not applicable to IP2/3 reactor vessels. However, the corresponding Table 2 line item indicates that the reactor vessels are supported on support pads, which are usually welded to the underside of the coolant nozzles and rests on steel base plates atop a support structure attached to the concrete foundation. Discuss how the fatigue cracking of support pad attachment welds are managed for IP2/3 reactor vessels. B) In LRA Section 3.1.2.2.1, Entergy states that no fatigue analysis was required for the pressurizer support skirts since the inservice inspection program will manage the cracking due to fatigue. In accordance with 10CFR54.21(c)(iii), demonstrate that the IP2/3 ISI program adequately manages the cracking due to fatigue for the period of extended operation. Specifically, include in the discussion the inspection methods, frequency, acceptance criteria, and past operating experience on the pressurizer support skirts at IP2/3. c) LRA Table 3.1.1, item 3.1.1-7 addresses cracking due to fatigue (as a TLAA) for support skirts, attachment welds, and pressurizer relief tank (PRT) components (in addition to RCPB closure bolting and studs, SG components, piping external surfaces and bolting) in the RCS, made out of carbon or stainless steel. In LRA Table 3.1.2-3, Entergy indicates a TLAA line item referring to Table 3.1.1-7 for the RCS components. The corresponding GALL Table 2-item IV.C2-10 (R-18) referencing RCS components for this TLAA, includes piping and pipe components external surfaces and bolting. LRA Table 2 line items associated with this TLAA do not include the support skirts and/or attachment welds for RCS components (e.g., RCP, SG, PRT) other than the pressurizer and PRT components. Clarify if these components (except RV attachment weld and pressurizer	a)The support pads for the reactor vessel are a part of the inlet and outlet nozzle forgings and are evaluated as part of those nozzles. The fatigue analyses of the reactor vessel discussed in LRA Section 4.3.1.1 include the inlet and outlet nozzles. (Ref. RPV stress reports CENC-1110 and CENC-1122) b)The second paragraph of Section 3.1.2.2.1 mentions the use of ISI to manage the effects of aging on the pressurizer support skirt only as additional information related to fatigue. The LRA does not say that a fatigue analysis is not required because of ISI; it just says that ISI manages cracking, including cracking due to fatigue, of the support skirt. Specifically, ISI Category B-K addresses the support skirt. No fatigue analysis exists for the support skirt. This is consistent with NUREG-1801 line item IV.C2-16, as shown in LRA Tables 3.1.2-3 (pages 3-120 and 3-138). Note E applies for these entries because the IPEC ISI program is described as a plant-specific program. ISI information was made available onsite for review. LRA Section 3.1.2.2.1, second paragraph, will be clarified to eliminate discussion of the aging management review results for the support skirt because the aging management review results are provided in the Section 3 LRA tables. The paragraph will be revised to read as follows. "Evaluation of the fatigue TLAA for the Class 1 portions of the reactor coolant pressure boundary piping and components, including those for interconnecting systems, is discussed in Section 4.3.1. Cracking, including cracking due to fatigue, will be managed by the Inservice Inspection Program." c)Reactor Vessel – Supported by the nozzles, (see response to part a) above. Steam Generators – Supported by pads attached to the steam generator primary channel heads. The channel heads (which includes the integral pads) are listed in Table 3.1.2-4 – IP2 and Table 3.1.2-4 - IP3. No fatigue analysis exists for the steam generator support pads, and aging effects are managed by the ISI program. Pressurizer – Supported by support skirts that are listed in Table 3.1.2-3 – IP2 and Table 3.1.2-3 - IP3. See the response to part b) above. Reactor coolant pumps – The reactor coolant pumps are supported by "feet" that are attached directly to the pump casing. The pump casings (which include the integral feet) are listed in Table 3.1.2-3 – IP2 and Table 3.1.2-3 - IP3. No fatigue analysis exists for the reactor coolant pump supports, and aging effects are managed by the ISI program. Pressurizer Relief Tank – Not part of the reactor coolant pressure boundary and no fatigue analysis is required for this tank. This tank is in scope for license renewal only as a non-safety related component whose failure could affect safety related equipment. Clarification to be incorporated into the LRA. (Applies to part (b) only.)

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	support skirts) are within the scope of LR for IP2/3. If such components are within the scope of the license renewal, then provide technical justification why these components are not subject to cracking due to fatigue for IP2/3 and included in the Table 2 items of the RCS.	
192	In LRA Table 3.1.2-4 there are several line items referencing Table 1 item 3.1.1-12 and Table 2 line item IV.D2-8 (R-224) for secondary side once-through steam generator components and crediting water chemistry control – primary and secondary to manage loss of material. Only one line item referring to carbon steel SG tubesheet with Ni-alloy clad on the primary side is subject to one-time inspection (in accordance with plant-specific note 104) for detecting and evaluating the effectiveness of managing the aging effect by the water chemistry control program. It is noted that Table 2 line items (IV.D1.9 and IV.D1.12) for recirculating SG components require SG integrity AMP to evaluate the effectiveness of the water chemistry control – primary and secondary for loss of material. Similarly, GALL Table 2 line item IV.D2-8 (R-224) for once-through SG requires a plant-defined method to evaluate the effectiveness of the water chemistry program to manage loss of material. Discuss what aging management activity will evaluate the effectiveness of the water chemistry control – primary and secondary for managing loss of material in these SG components (other than the tubesheet) exposed to treated water in the secondary side.	As stated in the Table 1 discussion column entries, the One-Time Inspection (OTI) Program is credited with verifying effectiveness of water chemistry programs. This is also reiterated in the OTI Program description in LRA Section B.1.27. However, LRA tables referencing Table 1 Item 3.1.1-12 and Table 2 Item IV.D2-8 (R-224) will be clarified to add plant-specific Note 104. Clarification to be incorporated into the LRA.
193	In LRA Table 3.1.2-4, IP2/3 ISI program and water chemistry control – primary and secondary AMPs manage loss of material in carbon steel SG shell components consistent with GALL Table 1 item 3.1.1-16 and Table 2 item IV.D1-12 (R-34). Explain why this line item in the LRA is marked with "Note E" indicating that the credited AMPs are not consistent with GALL recommendations. Note that similar Note E in Table 2 line items exist throughout the AMR Section 3.1 Tables whenever the IP2/3 ISI AMP (a plant-specific program) is credited for managing aging effects.	The IPEC ISI program is a plant-specific program that is not directly compared to the NUREG-1801 ISI program. Note E is used since NUREG-1801 does not specify a plant-specific program. See LRA Appendix B, Section B.1.18 for a detailed discussion of the IPEC ISI Program.
194	3.1-3 In LRA Table 1 item 3.1.1-17, Entergy states in its discussion, "The nozzles are not controlling for the TLAA evaluations." This Table 1 item refers to a TLAA for the loss of fracture toughness due to neutron irradiation embrittlement in the vessel beltline region. Demonstrate why the materials of the nozzles are not controlling for the TLAA evaluations.	Typical fluence at the nozzles of an IPEC vintage vessel is about 0.6 percent of the peak vessel fluence per WCAP-16212. Using the 1/4 T fluence values stated in Section 4.2 of the LRA, the ¼ T fluence at the IPEC nozzles will be less than 1E17 n/cm2 at 54 EFPY. 10CFR50 (Sections 50.60 and 50.61 along with Appendices G and H) requires evaluation of all components that exceed 1E17 n/cm2. Because the nozzles do not exceed 1E17 n/cm2, they were not evaluated. WCAP-16212, "Entergy Nuclear Operations, Incorporated, Indian Point Nuclear Generating Unit No. 3, Stretch Power Uprate, License Amendment Request Package," June 2004.
195	3.1-4 In LRA Table 1 item 3.1.1-21 and LRA Section 3.1.2.2.5, Entergy states, "SA508-Cl 2 forgings clad with stainless steel using a high-heat input welding process were not used in the IP2 or IP3 vessels." This line item is identified as not applicable to IP2/3. Describe the quantitative criteria that define "high-heat input welding process " and compare it to the welding parameters used for deposition of the SS cladding in the IP2 and IP3 vessels.	Underclad cracking is not a TLAA based on a WCAP analysis. WCAP-15338-A (WCAP-15338-A, A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants, October 2002) reviewed the issue of underclad cracking again in 2002. This report examined the growth of underclad cracks in susceptible plants, and showed that the crack growth would not threaten reactor vessel integrity for 60 years. The assumptions in this analysis are consistent with IP2 and IP3, four loop Westinghouse plants. As this WCAP is a 60-year calculation, it is not a TLAA. The NRC SER (included in the approved WCAP) states "The staff has concluded that the topical report is acceptable for all Westinghouse reactor pressure vessels (RPVs) because the underclad cracks satisfy the ASME Code flaw evaluation requirements for detected flaws, . . . The staff does not intend to repeat its review of the matters described in the report and found acceptable in the SER when the report appears as a reference in a license renewal application."

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		In summary, there is no underclad cracking TLAA associated with the IPEC reactor vessels.
196	3.1-5 In LRA Section 3.1.2.2.7, item 2 Entergy states that the water chemistry control – primary and secondary and thermal aging embrittlement of CASS AMPs manage cracking due to SCC in CASS RCS piping components. Entergy also states that the ISI program for some components supplements these AMPs. In LRA Table 3.1.2-3, only the CASS pipe fittings credit the ISI program in addition to water chemistry control – primary and secondary and thermal aging embrittlement of CASS AMPs. Discuss the criteria that require the IP2/3 ISI program for certain RCS components to be added as supplement to water chemistry control – primary and secondary and thermal aging embrittlement of CASS AMPs.	The criteria for specifying the ISI program to supplement other programs for CASS components is that the components are RCS pressure boundary components for which the ISI program applies. The only CASS component for which ISI is not credited is the pressurizer spray head (page 3.1-135), which is not a pressure boundary component subject to the inspections of ASME Section XI. The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will evaluate susceptibility to cracking due to stress corrosion cracking of non-pressure boundary components not subject to ISI.
197	3.1-6 In LRA Section 3.1.2.2.9, Entergy states that stress relaxation in stainless steel and nickel alloy reactor vessel internals screws, bolts, tie rods, and hold-down springs are not applicable since these components operate at a temperature 700°F in accordance with ASME Code, Section II, Part D, Table 4. Provide specific details of the materials of these IP2/3 RVI components and their operating temperature conditions in comparison to the Code threshold temperatures.	The reference value of 700°F from ASME Code, Section II, Part D, Table 4 is inappropriate for austenitic stainless steel bolting. This table of the code does contain this type of information, but not for austenitic stainless steel. The value for austenitic stainless steel is actually higher than 700°F. Per NUREG-1801, Section IX.F, the definition for creep provides the temperature thresholds where stress relaxation is not a concern. The thresholds are below 700°F for low alloy steel, below 1000°F for austenitic alloys, and below 1800°F for Ni-based alloys. Maximum fuel clad surface temperatures are approximately 660°F for the IP units. The maximum temperature of reactor vessel internals screws, bolts, tie rods, and hold-down springs is therefore less than the Code threshold temperatures. A copy of the applicable FSAR page was provided to the NRC. 3.1.2.2.9 Loss of Preload due to Stress Relaxation Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications (> 700°F). No IPEC internals components operate at > 700°F. Therefore, loss of preload due to stress relaxation (creep) is not an applicable aging effect for the reactor vessel internals components. Nevertheless, loss of preload of stainless steel and nickel alloy reactor vessel internals components will be managed to the extent that industry developed reactor vessel internals aging management programs address these aging effects. The IPEC commitment to these RVI programs is included in UFSAR Supplement, Appendix A, Sections A.2.1.41 and A.3.1.41.
198	3.1-7 In LRA Table 3.1.2-1, Entergy credits water chemistry control – primary and secondary and nickel alloy inspection AMPs to manage cracking in nickel alloy vessel internal attachment core support lugs (pads). This line item also references Table 1 item 3.1.1-31 and Table 2 item IV.A2-12 (R-88), which require the ISI program in addition to water chemistry control – primary and secondary and nickel alloy inspection AMPs. Clarify this discrepancy.	IPEC did not explicitly credit the ISI Program because the Nickel Alloy Inspection Program includes the applicable ISI inspections that are performed on these components. For clarification, Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 will be modified to explicitly include ISI in addition to Water Chemistry Control – Primary and Secondary and Nickel Alloy Inspection programs to manage the effects of aging on core support lugs (pads). Clarification to be incorporated into the LRA.
199	3.1-8 In LRA Section 3.1.2.2.14, Entergy credits visual inspections under SG integrity AMP to manage wall thinning due to FAC that could occur in carbon steel FW rings and supports, as noted in NRC IN 91-19 at San Onofre 2/3. Although the description of the SG integrity AMP includes other mechanically induced phenomena, such as denting, wear, impingement damage, and fatigue, no details are found in the LRA about how the inspection methods and their evaluation are performed with regard to loss of material in carbon steel FW inlet ring and supports in the IP2/3 SGs. Discuss the type of visual inspections that could detect the wall thinning of these SG components,	As stated in the Steam Generator Integrity Program description, the program included processes for monitoring and maintaining secondary side components. Visual inspections are performed by qualified vendors. To date, feed ring inspections have not been performed in the IP2 steam generators since their replacement in 2000 but are scheduled in two steam generators in 2010. The feed rings were inspected in the IP3 SGs in 1992 (all 4), 1997 (34SG), 1999 (33SG), 2001 (32 SG) & 2007 (31&32 SGs). The inspections performed in 1997 through 2007 consisted of a visual exam of the OD of the ring and a fiberscope inspection of the ID of 5 selected J-nozzles (of 36 total) and the feed ring tee. The inspections also examined, visually, various support structures including the feedring hangers. The acceptance criterion is the absence of any anomalous conditions. Anomalous conditions require evaluation. No anomalies were noted in the inspections other than minor washed out areas of the exterior feed ring beneath the outlet of the J-nozzles. The next feed ring inspection for IP3 is planned in 2 SGs

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	the acceptance criteria and operating experience associated with these activities at IP2/3.	in 2013.
200	3.1-9 In LRA Section 3.1.2.2.16, Entergy credits water chemistry control – primary and secondary and steam generator integrity program for managing cracking in carbon steel with Ni-alloy clad in steam generator tubesheet primary side. The Table 2 line item in LRA Table 3.1.2-4 references Table 1 item 3.1.1-35 and GALL item IV.D2-4 (R-35); these both specify the implementation of applicable plant commitments to (1) NRC Orders, Bulletins and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines. LRA Section A.2.1.34, which documents the UFSAR updates for the SG Integrity AMP, does not contain this commitment. Explain why this is not specifically documented in LRA Section A.2.1.34 as a LR commitment.	The commitment to implement NRC Orders, Bulletins, Generic Letters, and staff-accepted industry guidelines associated with nickel alloys are listed in Sections A.2.1.20 and A.3.2.1.20, Nickel Alloy Inspection Programs. These commitments are not listed in LRA Section A.2.1.34 because they do not apply to the Steam Generator Integrity Program. IPEC will apply NRC orders, bulletins, generic letters, and staff-accepted industry guidelines associated with nickel alloys to steam generator tubesheet primary side, if applicable. For clarification, Section 3.1.2.2.16 will be revised to state "IPEC will apply NRC orders, bulletins, generic letters, and staff-accepted industry guidelines associated with nickel alloys to steam generator tubesheet primary side, if applicable." Clarification to be incorporated into the LRA
201	3.1-10 In LRA Table 1 item 3.1.1-52, Entergy provides an explanation why cracking due to SCC, loss of material due to wear, loss of preload due to thermal effects, gasket creep, and self-loosening are not applicable to IP2/3 CS and SS RCPB pump valve closure bolting, and those in high pressure and high temperature environment. In fact, there were no Table 2 line items addressing these aging effects in both LRA Tables 3.1.2-3 and -4. GALL Table 2 items IV.C2-7, and IV.D1-1 and -2 for cracking, and items IV.C2-8 and IV.D1-10 for loss of preload due to thermal effects, gasket creep, and self-loosening credits the bolting integrity AMP for managing these aging effects. Moreover, loss of material due to corrosion in bolts exposed to indoor air environment is managed by the bolting integrity AMP [LRA Table 1 item 3.1.2-23, and LRA Table 2 item V.E-4 (EP-25)]. Note that IP2/3 bolting integrity AMP is consistent with GALL AMP XI.M18, bolting integrity program and based on the LRA, the IP2/3 bolting integrity AMP manages all the above-mentioned aging effects. Provide technical justification for the following: a)Applied stress for SS closure bolting applications at IP2/3 is much less than 100ksi. What is the basis for a threshold of 100ksi in the bolting materials at IP2/3 when cracking of bolting due to SCC is not an aging effect requiring aging management? b)Loss of material due to wear is not a significant aging effect for the bolting based on industry experience. Event driven conditions such as galling are not aging-related degradation. c)Loss of preload due to stress relaxation is not an applicable aging effect. Note that temperature condition is one of many factors (e.g., vibration, thermal cycles) that may cause loosening of bolts even in a benign thermal environment.	a) Leakage of primary coolant or the interaction between joint lubricants/sealing compounds and water could provide the aggressive environment needed for SCC in bolting materials. Since high strength bolting (>150 ksi yield strength) is not used for reactor coolant pressure boundary bolting applications, cracking due to stress corrosion cracking is not applicable. Citing the 100 ksi applied stress threshold for susceptibility to SCC is not required and will be removed from the discussion section for line item 3.1.1-52. b) Loss of material due to wear is not a signigicant aging effect for RCPB bolting because wear is the result of relative motion between two surfaces. Loss of material due to wear is not a significant aging effect for RCPB bolting because wear is the result of relative motion between two surfaces and any relative displacements or movements during normal plant operations are small and the resulting loss of material minimal. The relative motion between bolting and the connected surface that can occur during periodic assembly/disassembly for inspection maintenance are not related to normal aging. As described in LRA Table 3.1.1, item 3.1.1-52, occasional thread failures, such as galling (or improper fit-up/assembly), are event driven conditions that are resolved as required. Therefore, loss of material due to wear of RCPB bolting, both stainless steel and low alloy steel, carbon steel, is not a significant aging effect. Industry operating experience documented in various sources, such as the Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3, EPRI, Palo Alto, CA: 2001. 1003056 (Mechanical Tools), supports that the most common failures of pressure retaining bolting in safety-related applications were attributed to boric acid wastage and a few instances of stress corrosion cracking. No instances of bolting wear have been identified in site or industry documentation that were attributable to normal aging, whereas event driven bolting failures are known to occur, and are corrected in the short-term. Furthermore, the operating experience discussion for the Bolting Integrity Program in NUREG-1801, Revision 1, Section XI.M18 does not address bolting wear as an aging mechanism for bolting. C) Loss of preload is a design-driven effect that requires management during the current license term as well as during the period of extended operation, but it is not an aging effect. Consequently, it does not appear in LRA tables. As stated in the LRA, the Bolting Integrity Program (LRA Section B.1.2) includes preventive measures to preclude or minimize loss of preload. The program includes periodic visual inspections of pressure-retaining components (including closure bolting) for signs of leakage that may be due to crack initiation, loss of preload, or loss of material due to corrosion. LRA Table 3.1.1, Item 3.1.1-52 discussion column will be clarified by inserting the following sentence after "Improper bolting application (design) and maintenance issues are current plant operational concerns and not related to aging effects or mechanisms that require management during the period of extended operation." "Nevertheless, the Bolting Integrity Program manages loss of preload for all external bolting in the reactor coolant system with the exception of the reactor vessel studs." Also, LRA Table 3.1.1, Item 3.1.1-52 discussion column will be clarified to remove " Not applicable."

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		Commitment 2 will be clarified to specifically state the Bolting Integrity Program manages loss of preload and loss of material for all external bolting. Clarification to be incorporated into the LRA.
202	In LRA Table 3.1.1 item 3.1.1-59, Entergy states, " The steam outlet nozzle contains a nickel alloy flow restrictor and the feedwater nozzle contains a nickel alloy thermal sleeve that isolate the carbon steel nozzles from high fluid velocities; therefore these components are not susceptible to FAC." Based on this argument, Entergy includes no Table 2 item for this aging effect. GALL Table 1 item 3.1.1-59 recommends flow-accelerated corrosion AMP to manage wall thinning in carbon steel SG nozzles and safe ends for the main steam, feedwater and AFW exposed to secondary water. Explain how the Ni-alloy flow restrictor isolates the steam nozzle and safe end; Ni-alloy thermal sleeves isolate the FW and AFW nozzles and safe ends, from exposure to high velocity treated water flow into or out of the SG, thus, requiring no aging management of wall thinning in the subject SG components.	Main steam – The flow restrictor covers the main steam nozzle with no inside radius with exposure to areas of high flow. In addition, the high quality steam in the vicinity of the main steam nozzle is not associated with FAC. The main steam nozzles are not in the IPEC FAC program. Aux Feedwater -- The auxiliary feedwater system is not normally in service and FAC of the auxiliary feedwater nozzles is not an applicable aging effect. Feedwater -- The safe end and thermal sleeve are nickel alloy (SG-564 per WNEP-8732) and are therefore not susceptible to FAC. Further review of the nozzle, thermal sleeve and safe end configuration shows that there is a portion of the carbon steel nozzle next to the feedwater piping that remains exposed to feedwater flow. This small section of the nozzle is susceptible to FAC, and is included in the IPEC FAC program. The LRA will be clarified as follows. Table 3.1.1, Item 3.1.1-59 will be revised to state: "The steam outlet nozzle contains a nickel alloy flow restrictor and is exposed only to high quality steam, consequently this nozzle is not susceptible to flow accelerated corrosion. The feedwater nozzle contains a nickel alloy thermal sleeve that isolates most of the carbon steel nozzles from fluid flow. However, a small portion of the feedwater nozzle next to the feedwater piping is exposed to feedwater flow and is susceptible to flow accelerated corrosion." Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 will be revised to add a line item to each table as follows. Feedwater nozzle / Pressure boundary / Carbon steel / Treated water (int) / Loss of material / Flow accelerated corrosion / IV.D2-7 / 3.1.1-59 / A Clarification to be incorporated into the LRA.
203	3.1-11 In LRA Table 3.1.1, item 3.1.1-62, Entergy states that cracking due to cyclic loading is addressed as cracking due to fatigue (presumably, as a TLAA). Entergy also states that the ISI program manages the cracking of SS piping >4" NPS. However, no Table 2 line item addresses cracking due to cyclic loading for SS and CS with SS clad piping in the RCS (i.e., hot leg, cold leg, surge line, and spray line) exposed to reactor coolant as required by 10CFR54.21(a). The GALL item 3.1.1-62 addresses cracking due to cyclic loading and recommends ISI program to monitor the cracking in the piping and pipe fittings. This is required in addition to the establishment of the cumulative usage factors due to fatigue (or cyclic) loadings in accordance with 10CFR54.21(c). Provide technical justification for not including these Table 2 line items in the LRA Table 3.1.2-3 for RCS components.	The discussion section for Table 3.1.1 line Item 3.1.1-62 is revised to state " Cracking due to cyclic loading is addressed in other items as cracking due to fatigue. The Inservice Inspection Program manages cracking of stainless steel piping > 4" nps." Table 3.1.2-3-IP2 and Table 3.1.2-3-IP3 line item "piping >4" nps / Treated borated water >140 deg F (int) / Cracking" is revised to add the following NUREG-1801 Vol. 2 item, Table 1 item, and Note. IV.C2-26 (R-56) / 3.1.1-62 / E Information to be incorporated into the LRA.
204	3.1-12 In LRA Table 3.1.1, item 3.1.1-64, Entergy states, " The Inservice Inspection and Water Chemistry Control – Primary and Secondary Programs manage cracking in steel with stainless steel or nickel alloy clad components. Cracking of stainless steel components is addressed in other lines." Identify which other lines address cracking of stainless steel components in the pressurizer exposed to treated borated water.	All pressurizer components are included in Tables 3.1.2-3-IP2 and 3.1.2-3-IP3. These tables identify pressurizer stainless steel components exposed to treated borated water that have cracking as an aging effect requiring management. Items that include pressurizer components of stainless steel subject to cracking are heater sheaths, heater wells, manway insert plate, pressurizer penetration, pressurizer spray head, pressurizer spray head coupling and locking bar, thermal sleeve, and thermowell. The corresponding Table 1 rollup items are lines 3.1.1-24, 68 and 70.
205	3.1-13 In LRA Table 3.1.1, item 3.1.1-65, Entergy addresses cracking due to PWSCC in Ni-alloy RV	a. IPEC did not explicitly credit the ISI program because the ISI program inspections are inherently included in the Nickel Alloy Inspection Program. For clarification, Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 will be modified to explicitly include ISI in

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	upper head penetration nozzles, instrument tubes, and head vent pipe, and welds exposed to treated borated water. GALL recommends ISI, water chemistry control and Ni-alloy penetration nozzles (XI.M11A) AMPs, while Entergy credits water chemistry control and Ni-alloy inspection program. The IP2/3 AMP B.1.31 corresponds to the GALL AMP XI.M11A and manages PWSCC of Ni-based penetrations exposed to treated borated water. The Ni-Alloy inspection program (LRA B.1.21) manages Ni-alloy components that are not covered by the RVH penetration inspection (B.1.31) and SG integrity (B.1.35) AMPs. A) Provide technical justification for not crediting the GALL-recommended ISI, water chemistry control and Ni-alloy penetration nozzles (XI.M11A) AMPs to manage cracking due to PWSCC in Ni-alloy RV upper head penetration nozzles, instrument tubes, and head vent pipe, and welds exposed to treated borated water. B) Discuss how the water chemistry control – primary and secondary and the Ni-alloy inspection AMPs would manage cracking in Ni-alloy nozzle safe end and welds (inlet/outlet safe ends and closure head vent), as indicated in LRA Table 2 items referencing Table 1 item 3.1.1-65. Note that the Table 2 item IV.A2-18 (R-90) referenced for these line items in LRA Table 3.1.2-1 also recommends ISI, water chemistry control, and Ni-alloy penetration nozzles (XI.M11A) AMPs, consistent with GALL Table 1 item 3.1.1-65.	addition to the Water Chemistry – Primary and Secondary Program and Nickel Alloy Inspection Program to manage the effects of aging on reactor vessel inlet/outlet nozzle safe end welds and closure head vent nozzle safe ends and welds. b. With the explicit addition of the ISI Program as described in Part a, this line item is consistent with the aging management recommendations of NUREG-1801 Table 1, Item 3.1.1-65. IPEC has a plant-specific Nickel Alloy Inspection Program that manages aging effects of Alloy 600 components and 82/182 welds in the reactor coolant system that are not addressed by the Reactor Vessel Head Penetration Inspection Program or the Steam Generator Integrity Program. As described in LRA Appendix B, Section B.1.21, this program detects degradation by using the examination and inspection requirements of ASME Section XI, augmented as appropriate in response to NRC Orders, Bulletins and Generic Letters, or to accepted industry guidelines. Clarification to be incorporated into the LRA.
206	3.1-14 In LRA Table 3.1.1, item 3.1.1-66, Entergy states, " This line was not used. Erosion at manways and handholes is the result of damage from leaking joints that have not been corrected. At IPEC leaks are fixed as soon as practical. If damage due to erosion has occurred, it would also be repaired." Based on this, Entergy has not included this line item in the LRA Table 3.1.2-4. GALL recommends ISI program (Class 2: which requires visual inspections during pressure testing) to manage loss of material due to erosion in carbon steel steam generator secondary manways and handholes (cover only) exposed to air with leaking secondary-side water and/or steam. Provide technical justification how Entergy ensures the preventive (that detect the damage due to erosion) and corrective measures (that repair the leakage) for leaking joints and thus, would manage loss of material due to erosion in these SG components.	Erosion at manways and handholes results from abnormal conditions, that is, leakage. This mechanism can cause loss of material independent of the age of the components. Pressure leak tests are required by ASME Section XI, IWC. Because ISI of secondary components manages potential leaks, erosion of manways and handholes due to leakage is not an applicable aging effect.
207	3.1-15 In LRA Table 3.1.1, item 3.1.1-68, Entergy states, " The Water Chemistry Control – Primary and Secondary and Inservice Inspection Programs manage cracking in most stainless steel and steel with stainless steel clad Class 1 components. For some components not subject to the Inservice Inspection Program, the Water Chemistry Control – Primary and Secondary Program manages cracking. The pressurizer spray head coupling and locking bar supports flow distribution within the pressurizer and are not part of the pressure boundary. The One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program." LRA Table 3.1.2-3 line item referring to these components and the Table 1	The pressurizer spray head locking bar and coupling were compared to heater sheaths in GALL line item IV.C2-20. Heater sheaths are pressure boundary parts, and thus credit ISI for management of cracking. The spray head locking bar and coupling are not pressure boundary parts and are not inspected by the ISI program. Consequently, ISI was not credited as an aging management program. Note E was used for this line item, indicating that the program is different from GALL – as explained in Item 3.1.1-68. In lieu of ISI, the Water Chemistry Control – Primary and Secondary Program was credited. The One-Time Inspection Program will verify the effectiveness of the Water Chemistry Control – Primary and Secondary Program. The criteria for including the One-Time Inspection Program in a Table 2 line item of the LRA are as follows. • When the intent is to confirm that an aging effect is not occurring or the aging effect is occurring very slowly as not to affect the component or structure intended function such that an aging management program is not warranted, the One-Time Inspection

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	item 3.1.1-68 [Table 2 item IV.C2-20 (R-217)] indicates that the water chemistry control AMP would manage the cracking. This is inconsistent with GALL recommendations as well as Entergy's statement in the Table 1 item 3.1.1-68. Clarify this discrepancy.	Program will be listed in the aging management program column. • If the associated line item in NUREG-1801 Vol. 2 specifies a program to verify the effectiveness of a listed program, then a plant-specific note will be included in the line item that states "The One-Time Inspection Program will verify effectiveness of the XXX program". One-Time Inspection will not be listed in the aging management program column. • If the associated line item in NUREG-1801 Vol. 2 does not specify the One-Time Inspection Program to verify effectiveness of the associated program, then only the program will be identified with no plant-specific note. This approach is followed to show consistency with the GALL line item. However, as stated in Appendix B.1.27 of the LRA, the One-Time Inspection Program verifies the effectiveness of all Water Chemistry Control programs regardless of whether the GALL line item specifies it. To be consistent with the above criteria, plant specific note 104 is not included in the line items for the pressurizer spray head locking bar and coupling identified on Pages 3.1-118 and 3.1-136 since the associated NUREG-1801 line item does not specify a verification program, such as, One-Time Inspection Program.
208	3.1-16 In LRA Table 3.1.1, item 3.1.1-69, Entergy states, " The Water Chemistry Control – Primary and Secondary and Inservice Inspection Programs manage cracking in stainless steel nozzles and penetrations. Nickel alloy used for such applications is compared to other lines." Identify which other lines applicable to Ni-alloy components exposed to reactor coolant and manage cracking due to SCC and PWSCC.	Item 3.1.1-69 is a rollup for one line item, IV.A2-15. This item is used for comparison only to the inlet and outlet nozzle safe ends and the bottom head drain safe ends. There are numerous lines in Tables 3.1.2-1 through 3.1.2-4 that have nickel alloy parts subject to SCC. A few examples include the control rod drive penetrations (which have their own programs), inlet/outlet nozzle safe end welds on Pages 3.1-50 and 3.1-63, and bottom head instrument penetrations on Pages 3.1-51 and 3.1-64. These are compared to Items IV.A2-18 and IV.A2-19 which in turn roll up to table entries 3.1.1-31 and 3.1.1-65.
209	3.1-17 In LRA Table 3.1.1, item 3.1.1-74, Entergy states, " Consistent with NUREG-1801 for some components. The Water Chemistry Control – Primary and Secondary and Steam Generator Integrity Programs manage cracking and loss of material of stainless steel and nickel alloy steam generator components exposed to secondary feedwater and steam. For some components, loss of material is managed by the Water Chemistry Control – Primary and Secondary Program. The One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program." LRA Table 3.1.2-4 line item referring to secondary handhole cover RTD well as well as boss for IP3 and the Table 1 item 3.1.1-70 [Table 2 items IV.D1-14 (RP-14) and IV.D1-15 (RP-15)] indicates that the water chemistry control AMP would manage the cracking. This is inconsistent with GALL recommendations as well as Entergy's statement in the Table 1 item 3.1.1-74. a) GALL Table 2 items IV.D1-14 (RP-14) and IV.D1-15 (RP-15) recommend SG integrity and water chemistry control AMPs. Justify why for some components the one-time inspection AMP is credited instead of GALL-recommended SG integrity AMP in LRA Table 1 item 3.1.1-74, specifically to manage cracking in the secondary handhole cover RTD well for IP3. b) Clarify why the plant-specific note 104 is not indicated for secondary handhole cover RTD well and boss for IP3 to manage cracking of secondary handhole cover RTD well and loss of material in secondary handhole cover RTD boss. The note would ensure that one-time inspection AMP is applicable to these two Table 2 line items.	a.) The RTD well for IP3 is not included specifically in GALL, we compared it to GALL line item IV.D1-15 as it was the same material and environment. However, IV.D1-15 is for anti-vibration bars. Table 3.1.2-4-IP3 will be modified to include the Steam Generator Integrity Program in addition to Water Chemistry Control – Primary and Secondary Program to manage the effects of aging on secondary handhole cover RTD boss and well. The discussion for Table 1 Item 3.1.1-74 will be modified to state "Consistent with NUREG-1801. The Water Chemistry Control – Primary and Secondary and Steam Generator Integrity Programs manage cracking and loss of material of stainless steel and nickel alloy steam generator components exposed to secondary feedwater and steam." b.) Table 3.1.2-4-IP3 will be clarified to include plant specific note 104 for line items for components secondary handhole cover RTD boss and secondary handhole cover RTD well where the Table 1 Item is 3.1.1-74. c.) A steam generator RTD in the secondary handhole cover is unique to IP3. Information to be incorporated into the LRA.

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	C) Since both IP2 and IP3 steam generators are Westinghouse Model 44F, explain why LRA Table 3.1.2-4-IP2 does not include line items for secondary handhole cover RTD well and boss, similar to LRA Table 3.1.2-4-IP3.	
210	3.1-18 In LRA Table 3.1.1, item 3.1.1-84, Entergy states, " The Water Chemistry Control – Primary and Secondary Program manages cracking in one nickel alloy steam generator component exposed to secondary feedwater or steam. The One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program." LRA Table 3.1.2-4 line item referring to secondary handhole cover RTD boss cracking for IP3 and the Table 1 item 3.1.1-84 [Table 2 item IV.D2-9 (R-36)] indicates that the water chemistry control and one-time inspection AMPs would manage the cracking. Since both IP2 and IP3 steam generators are Westinghouse Model 44F, explain why LRA Table 3.1.2-4-IP2 does not include the line item for secondary handhole cover RTD boss, similar to LRA Table 3.1.2-4-IP3.	As discussed in the steam generator aging management review report (IP-RPT-AMM-34), only IP3 has an RTD in the secondary handhole cover.
211	3.1-19 In LRA Table 3.3.1, item 3.3.1-8, Entergy states, " Stainless steel components of some heat exchangers to which this NUREG-1801 line item applies, including the regenerative heat exchanger, are in the reactor coolant systems in series 3.1.2-x tables. The Water Chemistry Control – Primary and Secondary and Inservice Inspection Programs manage cracking of stainless steel heat exchanger bonnets and shells exposed to treated borated water. The Water Chemistry Control – Primary and Secondary Program manages cracking of stainless steel heat exchanger tubes. The program is augmented by the One-Time Inspection Program which will verify the absence of cracking in similar material environment combinations since the regenerative heat exchanger cannot be inspected internally." In LRA Table 3.1.2-3, Entergy credits water chemistry control – primary and secondary AMP to manage cracking in stainless steel HX tubes exposed to treated borated water and references Table 1 item 3.3.1-8. Clarify why the plant-specific note 314 that verifies effectiveness of the Water Chemistry Control – Primary and Secondary Program, is not indicated for HX tubes to manage cracking.	The criteria for including the One-Time Inspection Program in a Table 2 line item of the LRA are as follows. • When the intent is to confirm that an aging effect is not occurring or the aging effect is occurring very slowly as not to affect the component or structure intended function such that an aging management program is not warranted, the One-Time Inspection Program will be listed in the aging management program column. • If the associated line item in NUREG-1801 Vol. 2 specifies a program to verify the effectiveness of a listed program, then a plant-specific note will be included in the line item that states "The One-Time Inspection Program will verify effectiveness of the XXX program". One-Time Inspection will not be listed in the aging management program column. • If the associated line item in NUREG-1801 Vol. 2 does not specify the One-Time Inspection Program to verify effectiveness of the associated program, then only the program will be identified with no plant-specific note. This approach is followed to show consistency with the GALL line item. However, as stated in Appendix B.1.27 of the LRA the One-Time Inspection Program verifies the effectiveness of all water chemistry control programs regardless of whether the GALL line item specifies it. As stated in the discussion column for line item 3.3.1-8, the One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program for managing cracking in stainless steel components exposed to treated water. To be consistent with the criteria used for identifying One-Time Inspection, plant specific note 104 will be included for the line item of HX tubes exposed to treated borated water with cracking as an aging effect on Page 3.1-111 and Page 3.1-129. Clarification to be incorporated into the LRA
212	3.1-20 In LRA Table 3.4.1, line items 3.4.1-14 (for cracking) and 3.4.1-16 (for loss of material), Entergy states that consistent with NUREG-1801, Water Chemistry Control – Primary and Secondary Program manages cracking and loss of material in stainless steel components exposed to treated water. The One-Time Inspection Program is used to verify the effectiveness of the water chemistry program. In LRA Table 3.1.2-4, Entergy credits water chemistry control – primary and secondary AMP to manage cracking and loss of material in stainless steel piping, tubes and valves exposed to treated water and references	As stated in the discussion column for line item 3.4.1-14 and 3.4.1-16, the One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program for managing cracking and loss of material in stainless steel components exposed to treated water. LRA Table 3.1.2-4 credits water chemistry control – primary and secondary AMP to manage cracking and loss of material in stainless steel piping, tubes and valves exposed to treated water and references Table 1 items 3.4.1-14 and 3.4.1-16. Note C, "Component is different, but consistent with NUREG-1801 item for material, environment, aging effect and aging management program. AMP is consistent with NUREG-1801 AMP" was applied to these line items. The criteria for including the One-Time Inspection Program in a Table 2 line item of the LRA are as follows.

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	Table 1 items 3.4.1-14 and 3.4.1-16. Plant-specific notes for the steam and power conversion system do not include one that verifies the effectiveness of the Water Chemistry Control – Primary and Secondary Program for managing cracking and loss of material. Discuss how Entergy intends to verify the effectiveness of the Water Chemistry Control – Primary and Secondary Program for managing cracking and loss of material in SS components exposed to treated water.	• When the intent is to confirm that an aging effect is not occurring or the aging effect is occurring very slowly as not to affect the component or structure intended function such that an aging management program is not warranted, the One-Time Inspection Program will be listed in the aging management program column. • If the associated line item in NUREG-1801 Vol. 2 specifies a program to verify the effectiveness of a listed program, then a plant-specific note will be included in the line item that states "The One-Time Inspection Program will verify effectiveness of the XXX program". One-Time Inspection will not be listed in the aging management program column. •If the associated line item in NUREG-1801 Vol. 2 does not specify the One-Time Inspection Program to verify effectiveness of the associated program, then only the program will be identified with no plant-specific note. This approach is followed to show consistency with the GALL line item. However, as stated in Appendix B.1.27 of the LRA the One-Time Inspection Program verifies the effectiveness of all water chemistry control programs regardless of whether the GALL line item specifies it. □To be consistent with the criteria for using plant specific notes to identify the use of the One-Time Inspection Program, plant specific Note 104, "The One-Time Inspection Program will verify effectiveness of the Water Chemistry Control – Primary and Secondary Program" is applicable to Table 3.1.2-4-IP2 and 3.1.2-4-IP3 line items for steam generator instrumentation piping, tubing and valve body that roll up to Table 1 Items 3.4.1-14 and 3.4.1-16. Clarification to be incorporated into the LRA.
213	3.3-1 LRA Table 1 item 3.3.1-1: How is SRP 4.7 generic guidance implemented to address cumulative fatigue damage of "steel cranes-structural girders?	The Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR) provides guidance to Nuclear Regulatory Commission staff for the review of time-limited aging analyses, which are defined in 10 CFR 54.3. The SRP 4.7 generic guidance does not mention steel cranes. Entergy searched CLB documentation for analyses associated with the cranes that met the definition of TLAA and concluded that there was no TLAA associated with fatigue of the cranes. Details of this determination are contained in IPEC document IP-RPT-06-LRD03, " TLAA and Exemption Evaluation Results." Because there was no TLAA, this discussion is not included in Section 4 of the LRA.
214	3.3-2 LRA Table 1 item 3.3.1-5 states that the only stainless steel heat exchanger components exposed to treated water in the auxiliary systems are in the steam generator secondary side sample coolers, which are addressed in other lines. Where and how is this addressed?	The steam generator secondary side sample coolers aging management review results are provided in LRA Table 3.3.2-19-38-IP2. These heat exchangers are included in scope for 54.4(a)(2) for potential spatial interaction. The tube side of the heat exchanger can experience temperature above 140°F. However, because the shell prevents potential spatial interaction, the tube side has no intended function. The shell side of the coolers does not experience temperatures above 140°F.
215	3.3-3 LRA Table 1 item 3.3.1-6: Does the diesel exhaust piping have an intended function for LR? Define. Is it subject to aging management under any credited AMP?	Tables 3.3.2-14-IP2, 3.3.2-14-IP3, 3.3.2-15-IP2, and 3.3.2-16-IP2 list stainless steel exposed to diesel exhaust with a pressure boundary intended function. As indicated in these tables and discussed in Section B.1.29, the Periodic Surveillance and Preventive Maintenance Program includes inspection of exhaust system components. These components will be inspected for loss of material at least once every six years during the period of extended operation.
216	3.3-4 LRA Table 1 item 3.3.1-8: Confirm that the Inservice Inspection Program mentioned in the first paragraph is credited for managing cracking due to SCC for the regenerative heat exchanger components, consistent with the reactor coolant systems in series 3.1.2-x tables. Correct the second paragraph to be consistent with this.	In LRA Table 3.3.1 item 3.3.1-8, the first paragraph is identifying the use of this line item for a heat exchanger in the reactor coolant pressure boundary (Section 3.1 of the LRA). The regenerative heat exchangers for Indian Point are part of the reactor coolant system pressure boundary and therefore the Inservice Inspection Program is identified as managing the aging effect of cracking of these components. This first paragraph is consistent with Tables 3.1.2-3-IP2/IP3 that identify for the regenerative heat exchanger that the Inservice Inspection and Water Chemistry Control-Primary and Secondary Programs will manage the aging effect of cracking. The 3.3.1-8 line item discussion covers all the lines in the 3.1.2-x tables that include this line item, but the details of which programs specifically apply to which parts of the heat exchangers is only provided in the 3.1.2-x tables. In LRA Table 3.3.1 item 3.3.1-8, the second paragraph is identifying the use of this line item for a heat exchanger in the auxiliary systems (Section 3.3 of the LRA). For the auxiliary systems, this line item is applied to the reactor coolant pump seal return heat exchangers. These heat exchangers are part of the chemical and volume control system and are listed in Table 3.3.2-6. This second paragraph is consistent with Tables 3.3.2-6-IP2/IP3 which identify that for the reactor coolant pump seal

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		return heat exchanger, the Water Chemistry Control-Primary and Secondary Program, augmented by the One Time Inspection Program, will manage the aging effect of cracking. Since these paragraphs are describing two different sections of the LRA, there is not an inconsistency. No LRA change is necessary.
217	3.3-5 LRA Table 1 items 3.3.1-10, -41: Compare the bolting used in IP 2/3 auxiliary systems to the high-strength bolting addressed by this GALL Table 1 line item. Are the IP 2/3 bolts replaced during maintenance?	High strength bolts are defined by the Mechanical Tools (EPRI Report 1010639) as those with yield strength of greater than 150 ksi. The bolting used in non-Class 1 components is not high strength bolting. High strength steel bolts were not identified during the IPEC aging management review for auxiliary systems.
218	3.3-6 LRA Table 1 item 3.3.1-15,-16: LRA Section 3.3.2.2.7 item 1 states "Steel piping components and tanks of the reactor coolant pump oil collection system are not continuously exposed to a lubricating oil environment that is maintained by the Oil Analysis Program. Therefore this program is not credited for managing loss of material on these components. Instead these components are managed by the One-Time Inspection Program. This program will use visual or volumetric NDE techniques to inspect a representative sample of the internal surfaces to assure there is no significant corrosion." The OTI program is NOT a program that manages aging. It confirms the absence of degradation. If degradation is found, then an aging management program needs to be developed. Revise the LRA accordingly and identify what actions will be taken if degradation is discovered by the OTI.	The OTI Program, in addition to verifying the effectiveness of an aging management program (AMP), is also utilized to confirm the absence of an aging effect where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. For the RCP oil collection system, there will be confirmation, utilizing the OTI Program, that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly as not to affect component intended functions. In either event, the OTI Program serves as the means of detecting aging effects and triggering additional action in response to any adverse findings. In this sense, the OTI Program manages potential aging effects. As stated in the Monitoring and Trending attribute of the OTI Program, unacceptable inspection findings are evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections and for monitoring and trending the results. A one-time inspection of RCP oil collection system components after over 30 years of operation will provide valid information regarding whether ongoing periodic inspection through the period of extended operation is warranted.
219	3.3-7 LRA Table 1 item 3.3.1-42: Does IP 2/3 have bolting exposed to air with steam or water leakage in Auxiliary Systems? If yes, why is this line item not used?	IP2/3 does not have bolting exposed to air with leakage as a normal environment for bolted connections for auxiliary systems. If a leak occurs, it is corrected under the site corrective action or corrective maintenance programs. Therefore, as identified in Table 3.3-1, Item 3.3.1-42 was not used. The program specified in Item 3.3.1-42 is Bolting Integrity. The Bolting Integrity Program is applied to steel closure bolting as indicated by other items including 3.3.1-43, 3.3.1-44 and 3.3.1-55.
220	3.3-8 LRA Table 1 item 3.3.1-45: How is loss of preload currently managed at IP 2/3, if not by the existing Bolting Integrity Program? Describe the IP 2/3 operating experience with loss of bolt pre-load. How is the absence of loss of bolt pre-load confirmed?	Loss of preload is managed by the Bolting Integrity Program. As described in LRA Section B.1.2, the Bolting Integrity Program includes preventive measures to preclude or minimize loss of preload and cracking. Operating experience with loss of bolt pre-load at IPEC has been consistent with that experienced within the industry. IPEC has taken actions to address NUREG–1339, Resolution to Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants. These actions include implementation of good bolting practices in accordance with EPRI NP-5067, Good Bolting Practices. During the period of extended operation, the Bolting Integrity Program will be consistent with the program described in NUREG-1801, Section XI.M18, Bolting Integrity. As stated in NUREG-1801, Section XI.M18, under Detection of Aging Effects, the absence of loss of bolt preload is confirmed by visual examination during system leakage testing of all pressure-retaining Class 1, 2 and 3 components, according to Tables IWB 2500-1, IWC 2500-1, and IWD 2500-1, respectively. In addition, degradation of the closure bolting due to crack initiation, loss of prestress, or loss of material due to corrosion of the closure bolting would result in leakage. The extent and schedule of inspections, in accordance with Tables IWB 2500-1, IWC 2500-1, and IWD 2500-1, combined with periodic system walkdowns, assure detection of leakage before the leakage becomes excessive. For other pressure retaining bolting, periodic system walkdowns assure detection of leakage before the leakage becomes excessive.
221	3.3-9 LRA Table 1 items 3.3.1-46, 47, 50, 51 and 52 state that the One-Time Inspection Program for Water Chemistry will use visual inspections or non-destructive examinations of representative	For Table 2 items referencing Table 1 items 3.3.1-46, 47, 50, 51 and 52 the Water Chemistry Control – Closed Cooling Water Program is selected to be consistent with NUREG–1801 Volume 2 items (AP-60, A-25, A-52, AP-12 and AP-80, respectively) which do not specify a verification program. No other program need be listed in Table 2 to demonstrate consistency. Nonetheless, in the Discussion column of

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	samples to verify that the Water Chemistry Control – Auxiliary Systems and Water Chemistry Control – Closed Cooling Water Programs have been effective at managing aging effects. Explain why Table 2 line items that reference Table 1 items 3.3.1-46, 47, 50, 51 and 52 do not refer to OTI.	Table 1 the One-Time Inspection Program for Water Chemistry is specified as the method for verification of the effectiveness of the Water Chemistry Control – Closed Cooling Water Program. The Table 2 line items that reference Table 1 items 3.3.1-46, 47, 50, 51 and 52 do refer to OTI by way of these references to Table 1 items. In addition, the One–Time Inspection Program in Section B.1.27 of the LRA states that this program confirms the effectiveness of water chemistry control programs.
222	3.3-10 LRA Table 1 item 3.3.1-53: Compare the Periodic Surveillance and Preventive Maintenance Program, which is credited to manage loss of material for carbon steel station air system components exposed internally to condensation, to the GALL- recommended Compressed Air Monitoring Program.	The GALL- recommended Compressed Air Monitoring Program primarily consists of air quality monitoring and leakage monitoring. The areas of the compressed air system identified with a condensation environment are either upstream of the system air dryers or in the service air portion of the system that contains no air dryers, such that air quality monitoring will not be an effective aging management activity. The Periodic Surveillance and Preventive Maintenance Program manages loss of material for carbon steel station air system components exposed to condensation by periodic visual inspection and other NDE techniques. These techniques will allow identification of aging effects prior to system leakage and possible loss of system function. The Periodic Surveillance and Preventive Maintenance Program will therefore be more effective than the GALL-recommended Compressed Air Monitoring Program in this portion of the compressed air system. The components in the compressed air system downstream of □the instrument air dryers are exposed to an environment of treated (dried) air since they are downstream of the air dryers. The air dryers control the dew point of the air to ensure that condensation in the piping downstream of the dryers will not occur. The air dryers include dew point sensors with dew point indication and alarms to ensure that the proper dew point is maintained. In addition, the system is monitored at various points for dew point, particulates, and hydrocarbons in accordance with GL 88-14 requirements. These measurements are taken by site procedures 2-CY-2625 and 3-CY-2625 and trended. All actions required by GL 88-14 have been completed on IP2 and IP3. This ensures the air remains dry and as such the environment in this portion of the instrument air systems is identified as dried air. This is consistent with the definition of dried air in NUREG-1801 Vol. 2 Table IX.D which states that environment of air, dry is air that has been treated to reduce the dew point well below the system operating temperature which is the same as the treated air environment used in the IPEC LRA. □With this environment of dried air there are no aging effects requiring management and no aging management program as specified in NUREG-1801 Vol. 2 Section VII.J. If the PSPM program inspections in the portions of the compressed air system that contain condensation detect significant degradation an extent of condition review would be required for the entire compressed air system to ensure degradation is not occurring in other portions of the system. This would be accomplished as part of the corrective action program.
223	3.3-11 LRA Table 1 item 3.3.1-54: GALL recommends a periodic monitoring program (Compressed Air Monitoring) for this line item. Explain why confirmation of the lack of degradation is sufficient for IP 2/3.	The components included in this line item are in the portion of the compressed air system upstream of the instrument air system air dryers or in the service air portion of the system that doesn't contain air dryers such that they are constantly exposed to a condensation environment. Loss of material due to pitting and crevice corrosion is a potential aging effect but is not expected for stainless steel components exposed to internal condensation due to their high resistance to corrosion especially in a benign environment such as condensation. The One-Time Inspection Program will confirm the absence of aging effects for these compressed air system components exposed to condensation by visual inspection and other NDE techniques. These techniques will allow identification of the absence of significant aging effects before possible loss of system or component function. If the OTI program identifies pitting or crevice corrosion, a periodic inspection program would be established as part of the corrective action program. The GALL- recommended Compressed Air Monitoring Program primarily consists of monitoring air quality and leakage to ensure that significant condensation is not occurring that would result in corrosion. The use of this program is therefore not appropriate for managing the components exposed to this condensation environment. The components in the compressed air system downstream of the instrument air dryers are exposed to an environment of treated (dried) air since they are downstream of the air dryers. The air dryers control the dew point of the air to ensure that condensation in the piping downstream of the dryers will not occur. The air dryers include dew point sensors with dew point indication and alarms to ensure that the proper dew point is maintained. In addition, the system is monitored at various points for dew point, particulates, and hydrocarbons in accordance with GL 88-14 requirements. These measurements are taken by site procedures 2-CY-2625 and 3-CY-2625 and trended. All actions required by GL 88-14 have been completed on IP2 and IP3. This ensures the air remains dry and as such the environment in

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		this portion of the instrument air systems is identified as treated (dried) air. This is consistent with the definition of dried air in NUREG-1801 Vol. 2 Table IX.D which states that environment of air, dry is air that has been treated to reduce the dew point well below the system operating temperature which is the same as the treated air environment used in the IPEC LRA. With this environment of dried air there are no aging effects requiring management and no aging management program as specified in NUREG-1801 Vol. 2 Section VII.J. If the One-Time Inspection program inspections in the portions of the compressed air system that contain condensation detect degradation an extent of condition review would be required for the entire compressed air system to ensure degradation is not occurring in other portions of the system. This would be accomplished as part of the corrective action program.
224	3.3-12 LRA Table 1 item 3.3.1-72: Identify and describe the applications of the External Surfaces Monitoring Program to manage loss of material for internal surfaces exposed to condensation. How is the environment determined to be the "same"?	The line items in Tables 3.3.2-2-IP2 and 3.3.2-2-IP3 pertain to piping vent stacks on the service water system with the internal and external surfaces exposed to the same indoor air environment. The tables conservatively identify the environment as condensation corresponding to the external environment for piping containing much cooler service water. The line items will be revised to specify an environment of air – indoor both internally and externally for this section of piping in Tables 3.3.2-2-IP2 and 3.3.2-2-IP3. Since the internal surfaces are exposed to the same environment and subject to the same aging effects as the external surfaces, the condition of the external surfaces will be representative of the condition of the internal surfaces. Significant loss of material if found on the external surfaces, will result in appropriate corrective actions that apply to internal surfaces as well as external. In this manner, the External Surfaces Monitoring Program will manage loss of material on internal carbon steel surfaces exposed to indoor air. Clarification to be incorporated into the LRA.
225	3.3-13 LRA Table 1 item 3.3.1-79: Explain the differences between those components that require the Service Water Integrity AMP and those components that only require OTI confirmation of lack of degradation. The material, environment, and function appear to be the same in both cases.	The Service Water Integrity Program is an existing program that relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the service water system are managed through the period of extended operation. This program does not apply to other systems with stainless steel components exposed to raw water. The raw water environment is not limited to service water. For most of these systems, the environment includes water that was originally treated but that is no longer controlled by a chemistry program. Therefore, the OTI program manages degradation for non-service water system components for which no significant aging effects are expected.
226	3.3-14 In accordance with Table 1 item 3.3.1-87, the Boraflex Monitoring Program, supplemented by the Water Chemistry Control – Primary and Secondary Program, manages the degradation of Boraflex. LRA Table 3.3.2-1-IP2/3 credits Water Chemistry Control for managing loss of material and cracking and Boraflex Monitoring for change in material properties. Confirm that the Boraflex Monitoring Program, supplemented by the Water Chemistry Control – Primary and Secondary Program manages all three Table 2 items addressing loss of material, cracking and change in material properties.	The Boraflex Monitoring Program, supplemented by the Water Chemistry Control – Primary and Secondary Program manages the loss of material, cracking and change in material properties items in Table 3.3.2-1-IP2 for Boraflex. Table 3.3.2-1-IP2 line items for loss of material and cracking of Boraflex will be revised to add the Boraflex Monitoring Program, and to add Water Chemistry Control – Primary and Secondary Program to the item for change in material properties. This makes all three items consistent with the plant-specific discussion in Table 3.3.1, Item 3.3.1-87. Clarification to be incorporated into the LRA.
227	3.3-15 In accordance with LRA Table 1 item 3.3.1-13, the Boral Surveillance Program, supplemented by the Water Chemistry Control – Primary and Secondary Program, manages the degradation of Boral including the reduction of neutron-absorbing capacity. Confirm that the Table 3.3.2-1-IP2/3 line item also includes the aging effect reduction of neutron-absorbing capacity.	The Boral Surveillance Program is applicable only to IP3. Table 3.3.2-1-IP3 identifies that loss of material is managed by the Boral Surveillance Program and the Water Chemistry Control – Primary and Secondary Program. A line item to include the aging effect of change in material properties will be added to Table 3.3.2-1-IP3, and LRA Section 3.3.2.2.6 will be changed to state that the aging effect reduction of neutron absorption capacity has not been an observed aging effect at IPEC. Clarification to be incorporated into the LRA.
228	3.3-16 In LRA Table 3.3.2-2-IP2/3 one line item for Cu alloy (>15% Zn) HX tubes exposed to treated water (ext), Service Water Integrity manages loss of material due to wear. Explain how the Service Water Integrity AMP manages components	If a heat exchanger is supplied service water, the Service Water Integrity Program applies to the heat exchanger. Part of the Service Water Integrity Program is to inspect the heat exchanger. The inspection includes the inspection of both side of the heat exchanger. This inspection would detect wear on the exterior of the tubes. In this case the HX is supplied service water (tube side) and treated water is on the outside of the tubes. Therefore, the Service Water Integrity Program manages wear

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	exposed to treated water.	of the exterior of the tubes exposed to treated water.
229	3.3-17 In LRA Table 3.3.2-3-IP2/3 for Cu alloy (>15% Zn) HX tubes exposed to treated water (ext), there are two line items, one credits HX Monitoring and the other Service Water Integrity, to manage the same aging effect (loss of material due to wear). Explain the difference.	The difference is that the heat exchanger managed for wear by the Service Water Integrity Program is supplied by the service water system and the other heat exchanger is not supplied service water and, therefore, is not included in the Service Water Integrity Program. The Heat Exchanger Monitoring Program manages loss of material due to wear for this heat exchanger.
230	3.3-18 LRA Table 1 items 3.3.1-7and -8 indicate that the water chemistry program is augmented by the One-Time Inspection Program, which will verify the absence of cracking. . Explain why Table 2 line items in Table 3.3.2-6-IP2/3 and for other systems referring to these Table 1 items do not credit OTI.	Table 2 line items that refer to these Table 1 items do credit OTI. In the standard LRA format, Table 1 discussion items provide information that is applicable to the Table 2 line item that refers to the specific Table 1 item. As is correctly noted for line items 3.3.1-7 and 3.3.1-8 in this question, the water chemistry program is augmented by the One-Time Inspection Program, which will verify the absence of cracking. This is further discussed in section 3.3.2.2.4-1 of the LRA. Therefore, all Table 2 line items referring to items 3.3.1-7 and 3.3.1-8 explicitly credit OTI. In addition, Section B.1.27 of Appendix B in the IPEC LRA states "A one-time inspection activity is used to verify the effectiveness of the water chemistry control programs by confirming that unacceptable cracking, loss of material, and fouling is not occurring on components within systems covered by water chemistry control programs."
231	3.3-19 Provide technical justification why One-Time Inspection is not credited for verifying the effectiveness of the Oil Analysis AMP to manage cracking in stainless steel components exposed to lubricating oil, as listed in LRA Tables 3.3.2.14-IP2, 3.3.2.14-IP3, and 3.3.2.16-IP3.	While not explicitly listed for cracking of stainless steel in a lubricating oil environment in LRA Tables 3.3.2.14-IP2, 3.3.2.14-IP3, and 3.3.2.16-IP3, the One-Time Inspection Program is credited for verifying the effectiveness of the Oil Analysis AMP which manages cracking in stainless steel components exposed to lubricating oil. LRA Section B.1.27 states, "A one-time inspection activity is used to verify the effectiveness of the Oil Analysis Program by confirming that unacceptable cracking, loss of material, and fouling is not occurring on components within systems covered by the Oil Analysis Program." However, The One-Time Inspection Program will be consistent with the program described in NUREG-1801, Section XI.M32, One-Time Inspection. The One-Time Inspection Program descriptions in Sections A.2.1.26 and A.3.1.26 will be clarified by adding "cracking" as an aging effect confirmed during inspections of components managed by the Oil Analysis Program. Clarification to be incorporated into the LRA.
232	3.3-20 LRA Tables 3.3.2-11-IP2, -IP3, 3.3.2-14-IP2, -IP3, 3.3.2-15-IP2, -IP3, and 3.3.2-16-IP2, -IP3 all identify the aging effect "cracking-fatigue" associated with the environment "exhaust gas (int.) ". The components are all parts of exhaust systems for diesel generators. Three different approaches are identified for aging management: Fire Protection AMP in Tables 3.3.2-11-IP2, -IP3; Periodic Surveillance and Preventive Maintenance AMP in Tables 3.3.2-15-IP2, -IP3 and 3.3.2-16-IP3; TLAA-Metal Fatigue in Tables 3.3.2-14-IP2, -IP3 and 3.3.2-16-IP2. Describe the physical behavior that results in cracking due to fatigue, and the basis for the selected approach to managing this aging effect, for each of these 8 systems. Identify where in the LRA the applicable TLAAs are described. Also identify the associated TLAA documents that will be available for audit.	The physical behavior that results in cracking due to thermal fatigue is from the stresses that occur whenever expansion or contraction of a component occurs due to temperature changes. The concern for these components is the impact of an exhaust leak on engine operation. In order to impact engine operation any leak would have to be a quite large before it displaced significant quantities of intake air. A defect such as a crack could easily be detected through visual observation well before it reached a size that would impact engine operation and be a concern. Though not expected to occur on these exhaust system components due to their limited operation and design, cracking due to thermal fatigue has been conservatively identified as an aging effect requiring management. Three different approaches are identified for managing the aging effect of cracking-fatigue for the diesel exhaust components at Indian Point. The approach that is best for the individual engine varies based on its ASME code classification. The Fire Protection Program is credited for the fire □pump diesel exhaust components since the Fire Protection Program manages the fire pump diesel engines and their subcomponents and these are not ASME Code components. For the exhaust components on the emergency diesel generators and IP2 station blackout diesel where the components are ASME code components, non-Class 1 metal fatigue is identified in accordance with the temperature thresholds identified in Appendix H of the EPRI Mechanical Tools (EPRI 1010639). For exhaust components not associated with the fire pump diesel which are not ASME code qualified components (such as the exhaust components on the security generators and IP3 Appendix R diesel generator system), the Periodic Surveillance and Preventive Maintenance Program has been specified to manage cracking due to thermal fatigue. The Fire Protection Program is described in Section B.1.13 and identifies an enhancement to the program to manage cracking from fatigue through the use of inspections. These inspections will include visual or NDE techniques. The treatment of fatigue for non-Class 1 components in the EDG and Appendix R diesel systems is discussed in LRA section 4.3.2 and section 3.1 of report IP-RPT-06-

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		LRD04. The evaluation of these components is the same as discussed in the response to audit item 233 for ASME B31.1 piping and inline components. The Periodic Surveillance and Preventive Maintenance Program is discussed in LRA Section B.1.29 and identifies the management of the aging effects on the engine exhausts through the use of visual inspections or NDE techniques. Additional information on metal fatigue and TLAAs is available in LRD04 "TLAA – Mechanical Fatigue". The flexible connections and expansion joints in Tables 3.3.2-16-IP2, 3.3.2-14-IP2 and 3.3.2-14-IP3 should not be included as part of the TLAA evaluation since they isolate portions of the system from each other and would not be part of a specific stress analysis for the system or parts of the system. The line items for the flexible connection and expansion joint in Tables 3.3.2-16-IP2, 3.3.2-14-IP2 and 3.3.2-14-IP3 that identify TLAA-Metal Fatigue will be removed. Clarification to be incorporated into the LRA
233	3.3-21 In the series of LRA Tables 3.3.2-19-xx-IP2 and 3.3.2-19-xx-IP3, there are numerous line items (over 100) that specify "cracking-fatigue" as the aging effect and "TLAA-metal fatigue" as the aging management program. The components are mostly piping and valve bodies, but also include tubing, filter housing, heater housing, strainer housing, steam trap, flex joint, sight glass, thermowell, and flow element. Identify where in the LRA the applicable TLAAs are described. Also identify the associated TLAA documents that will be available for audit.	Section 4.3.2 of the LRA and Section 3 of IP-RPT-06-LRD04 discuss fatigue of non-Class 1 SSCs. Entergy identified cracking from fatigue for the non-Class 1 piping and in-line components (flow elements, tubing, piping, traps, housings, thermowells, valve bodies, etc.) that are above the temperature thresholds for cracking due to thermal fatigue identified in the EPRI Mechanical Tools Appendix H (EPRI 1010639). The design of ASME B31.1 piping and in line components in these systems incorporates the Code stress reduction factor for determining acceptability of piping design with respect to thermal stresses. In general, 7000 thermal cycles are assumed, allowing a stress reduction factor of 1.0 in the stress analyses. IPEC evaluated the validity of this assumption for 60 years of plant operation. The results of this evaluation indicate that the 7000 thermal cycle assumption is valid and bounding for 60 years of operation for the above component types with the exception of flex joints and sight glasses. Therefore, the pipe stress calculations are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). No TLAA were identified for non-piping components in LRA Tables 3.3.2-19-xx-IP2 and 3.3.2-19-xx-IP3. Additional information is available onsite in report IP-RPT-06-LRD04 "TLAA – Mechanical Fatigue" as discussed above. The flex joints should not be included as part of the TLAA evaluation since they isolate portions of the system from each other and would not be part of a specific stress analysis for the system or parts of the system and would not be subject to cracking based on their design to absorb thermal stresses. The line items for the flex joints in the LRA Tables 3.3.2-19-xx-IP2 and 3.3.2-19-xx-IP3 that identifies TLAA-Metal Fatigue will be removed. The sight glasses also should not be included as part of the TLAA evaluation but should be identified with the One-Time Inspection Program as an aging management program to confirm the absence of cracking due to thermal fatigue. For sight glass line items in LRA tables 3.3.2-19-12-IP2, 3.3.2-19-2-IP3, 3.3.2-19-14-IP3, and 3.3.2-19-27-IP3 that identify TLAA-Metal Fatigue in the AMP column, TLAA-Metal Fatigue will be changed to One-Time Inspection. Information to be incorporated into the LRA
234	AMR-3.4-1 The GALL Report (NUREG-1801) includes the Steam Turbine System and Extraction Steam System as part of the steam and power conversion system. Why are these two systems not included in the scope description of Steam and power conversion System, Section 3.4, included in Indian Point license renewal application?	The steam turbine system is listed as turbine generator system for IP2 and as main turbine generator for IP3. Extraction steam is included in main steam system for IP2 and is listed as extraction steam for IP3. As indicated in LRA Table 2.2-1a-IP2 and Table 2.2-1a-IP3, the IP2 main steam (MS), IP2 turbine generator (TURB), IP3 extraction steam (EX), and IP3 main turbine generator (MTG) systems are addressed in Section 3.3, Auxiliary Systems. The IP2 main steam (MS), IP2 turbine generator (TURB), IP3 extraction steam (EX), and IP3 main turbine generator (MTG) systems are in scope only for 10 CFR 54.4(a)(2) for physical interaction. The aging management review of the systems that have functions that met 10 CFR 54.4(a)(2) for physical interaction was done separately from the review of systems with intended functions that met 10 CFR 54.4(a)(1) or (a)(3). The results of this review were presented separately so that they could be reviewed separately on the basis of physical proximity rather than system function. This allows a reviewer to clearly distinguish which component types in a system were included for 10 CFR 54.4(a)(2) for physical interaction. Since most of these systems are auxiliary systems, they were added as part of the auxiliary systems section.
235	AMR-3.4-2 LRA Section 3.4.2.1, Materials, Environment, Aging Effects Requiring management and Aging Management Programs includes the list of AMPs applicable to each system covered under Section	The following criteria apply for including the One-Time Inspection Program in a Table 2 line item of the LRA. • When the intent is to confirm that an aging effect is not occurring or the aging effect is occurring very slowly as not to affect the component or structure intended function

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	3.4, Steam and Power Conversion Systems. It is observed that One-Time Inspection AMP is missing from the AMP lists provided for the Main Steam, Main Feedwater and Steam Generator Blowdown Systems. Since the GALL Report (NUREG-1801) recommends that One-Time Inspection Program is to be used to verify the effectiveness of Water Chemistry Control Program used by Indian Point in these systems, the list should have included One-Time Inspection along with the other AMPs to complete the list. Explain if Indian Point has a justification for not including One-Time Inspection Program in the lists of applicable programs.	such that an aging management program is not warranted, the One-Time Inspection Program will be listed in the aging management program column. • If the associated line item in NUREG-1801 Vol. 2 specifies a program to verify the effectiveness of a listed program, then a plant-specific note will be included in the line item that states "The One-Time Inspection Program will verify effectiveness of the XXX program". One-Time Inspection will not be listed in the aging management program column. • If the associated line item in NUREG-1801 Vol. 2 does not specify the One-Time Inspection Program to verify effectiveness of the associated program, then only the program will be identified with no plant-specific note This approach is followed to show consistency with the NUREG-1801 item. However, as stated in Appendix B.1.27 of the LRA, the One-Time Inspection Program verifies the effectiveness of all water chemistry control programs regardless of whether the NUREG-1801 item specifies it. Section 3.4.2.1 lists programs that manage aging effects for each of the systems included in Section 3.4. For the cases where OTI verifies effectiveness of a program that manages aging, such as water chemistry, OTI will not be listed in this section. If OTI is used as a program to confirm that an aging effect is not occurring or the aging effect is occurring very slowly it will be listed as a program as shown in Section 3.4.2.1.3 for the auxiliary feedwater system. The above criteria will be added to the LRA. Clarification to be incorporated into the LRA
236	AMR-3.4-3 LRA Tables 3.4.2-1-IP2 and 3.4.2-1-IP3 (Main Steam System) include several items pertaining to carbon steel and stainless steel piping, piping components, and elements that are exposed to indoor air environment. Does this piping (and piping components and elements) have bare surface exposed to the indoor air or is this piping insulated? If the piping has insulation, it's not directly exposed to the indoor air and the applicable line items will required to be revised.	Entergy used the Mechanical Tools (EPRI Report 1010639) for the identification of aging effects. As identified in the Mechanical Tools, the use of insulation is not credited with precluding the aging effects for the underlying metals. Insulation is not effective in preventing exposure of the underlying materials to air. Aging effects for the insulated piping are conservatively identified independent of any protective coating, including insulation.
237	AMR-3.4-4 In LRA Tables 3.4.2-X and 3.3.2-19-X, for several line items pertaining to carbon steel piping, piping components, and piping elements, Indian Point has utilized the GALL Report line item 3.4.1-29 for managing flow-accelerated corrosion. The "Aging Effect Requiring Management" columns in these tables indicate "loss of material" as the Aging Effect. To be consistent with the terminology used in GALL Table 4, Item 29, the "Aging Effect/Mechanism" should state "Wall thinning due to flow-accelerated corrosion" as the aging effect. All pertinent line items in the IP tables pertaining to the Flow-Accelerated Corrosion Program need to be corrected. Some examples of the IP2/IP3 tables to which this change applies are: 3.4.2-1-IP2, 3.4.2-1-IP3, 3.4.2-2-IP2, 3.4.2-2-IP3, 3.4.2-3-IP2, 3.4.2-3-IP3, 3.4.2-4-IP2, 3.4.2-4-IP3, and several 3.3.2-19-X tables.	Entergy used the EPRI Mechanical Tools (EPRI Report 1010639) for the identification of aging effects. As identified in the Mechanical Tools Appendix A page 3-7 for treated water, flow accelerated corrosion is loss of material caused by the relative movement between a corrosive fluid and a material surface. The Mechanical Tools is the guidance document used to determine aging effects for license renewal. This is also consistent with NUREG-1801 Table IX.F which describes flow-accelerated corrosion as a mechanism leading to loss of material and Table IX.E which defines the aging effect of wall thinning as the specific type of loss of material due to flow accelerated corrosion. The use of loss of material as the aging effect due to the mechanism of flow-accelerated corrosion has been accepted on previous license renewal applications including those for Point Beach, Browns Ferry, Palisades, Monticello, Millstone, Oyster Creek, FitzPatrick, Pilgrim and Vermont Yankee nuclear plants. For clarification, the Flow Accelerated Corrosion Program in Appendix B.1.15 will be revised to include a statement that the aging effect of loss of material managed by the Flow Accelerated Corrosion Program is equivalent to the aging effect of wall thinning as defined in NUREG-1801 Volume 2 Table IX.E. Clarification to be incorporated in the LRA.
240	AMR-3.4-5 Each LRA Table 3.4.2-1-IP2 and 3.4.2-1-IP3, Main Steam System, includes one line item pertaining to carbon steel piping externally exposed to " indoor air" with the aging effect listed as "none" and Table 1 item listed as "3.4.1-28" with notes "I & 401" in the last column. Note "I" implies that the aging effect in NUREG-1801 for this component, material, and environment combination is not applicable and Note "401" implies that these	a. The Table 3.4.2-1-IP2/3 line items for carbon steel piping with external exposure to "indoor air" and the following line for carbon steel piping with internal exposure to " indoor air" do not refer to the same piping. The internal "indoor air" line item is specific to the main steam safety valve (MSSV) tailpipe vents which provide a discharge flow path for MSSV discharge in the event of valve opening. The external exposure to "indoor air" line item is applicable to the main steam system piping that normally operates at a temperature above 212°F. A revision to the line item for the tailpipe is addressed in the response to "c" below. b. Note 401 does not apply to piping with indoor air flowing internal to the piping. It

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	components remain at high temperature during normal operation which precludes moisture condensation and the resulting corrosion. The next line item in these Tables is for the carbon steel pipe with internal exposure to "indoor air" with the aging effect listed as "loss of material" and Table 1 item listed as "3.2.1-32" and Note "E" in the last column. Note "E" implies that a different management program is credited for this line item. The aging management program included in these Tables for the second line item is "External Surfaces Monitoring." The aging management program used in GALL Report for line 3.2.1-32 is " Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The following three questions apply to the situation described above: a. Do these two line items described above represent the same piping, one line covering the internal and the other the external environment? Describe the function of this piping in the main steam system. b. What kind of indoor air is flowing through the piping that the high temperature stated in Note 401 is maintained in the piping? How the absence of corrosion is ascertained when the system cools down, e.g., during the plant shut down, refueling outages, and start up mode prior to attaining the normal operation high temperature mentioned in the Note? c. Explain how the "External Surfaces Monitoring" Program stated in the Table is used by IP to monitor the loss of material on the "internal" surface of the subject piping?	applies to components containing steam or water such that normal surface temperature is >212°F. In accordance with the EPRI Mechanical □Tools for external surfaces (Appendix E, page 3-2 of EPRI 1010639), a normal operating temperature of >212°F prevents moisture accumulation and above this temperature loss of material is not an aging effect requiring management. The main steam system during normal plant operation operates well above 212°F since the main steam temperature is approximately 500°F. No plant surface is always above the 212°F threshold, however the AMR evaluates the aging effects for the conditions during normal plant operation. For carbon steel in an indoor air environment, loss of material due to corrosion during the small percentage of time the system is below normal operating temperature is not an aging effect that requires management. c. As noted in the question, the External Surfaces Monitoring Program is cited in LRA Tables 3.4.2-1-IP2/3 to manage loss of material on the internal surface of the subject piping. However, upon further review, the following changes will be made to the LRA. Based on the MSSV tailpipes being open to the outdoor atmosphere, " outdoor air" will be specified for the piping internal surfaces in LRA Tables 3.4.2-1-IP2/3 with an aging management program of Periodic Surveillance and Preventive Maintenance (PSPM) Program instead of External Surfaces Monitoring Program. The Table 3.4.2-1-IP2/3 "Table 1 reference column" will be changed to 3.4.1-30 and the "Notes" column will change to Note E. Table 3.4.1, line item 3.4.1-30 discussion will also be revised to reflect the MSSV tailpipe. The PSPM Program will be changed (including LRA Appendix A and B descriptions) to include inspection of the tailpipes to manage loss of material from the internal surface. Table 3.4.1, Item 3.4.1-30 will be changed to reflect the outdoor air/internal surface material/environment combination for the MSSV tailpipes. The response, including LRA changes, is also applicable to the main steam system atmospheric dump valve silencers. Therefore, Table 3.4.2-1-IP2/IP3 Table 1 items pertaining to ADV silencers will also be similarly revised. Information to be incorporated into the LRA.
241	AMR-3.4-6 Each LRA Table 3.4.2-1-IP2 and 3.4.2-1-IP3, Main Steam System, includes one line item pertaining to carbon steel bolting externally exposed to " indoor air" with the aging effect listed as "none" and Table 1 item listed as "3.4.1-22" with notes "I & 401" in the last column. Note "I" implies that the aging effect in NUREG-1801 for this component, material, and environment combination is not applicable and Note "401" implies that these components remain at high temperature during normal operation which precludes moisture condensation and the resulting corrosion. The following questions apply to the situation described above: a. Which component or equipment in the main steam system these bolts are installed on? Describe how the high temperature as stated in Note "401" is maintained during the normal operation. Also explain how the absence of corrosion is ascertained when the system piping and the equipment on which this bolting is installed cools down, e.g., during the plant shut down, refueling outages, and the start up mode prior to attaining the normal operation high temperature mentioned in the Note. b. The GALL line item 3.4.1-22, as stated in the above tables, recommends the "Bolting Integrity Program" to manage the loss of material due to general, pitting and crevice corrosion in addition to	a. The bolting described in these mechanical tables is the bolting that is required to maintain the pressure boundary on the passive mechanical components such as valve bonnets and bolted flanges. In accordance with the EPRI Mechanical Tools for external surfaces (Appendix E of EPRI 1010639), a normal operating temperature of >212°F prevents moisture accumulation and above this temperature loss of material is not an aging effect requiring management. The main steam system during normal plant operation operates well above 212°F since the main steam temperature is approximately 500°F. No plant surface is always above the 212°F threshold, however the AMR evaluates the aging effects for the conditions during normal plant operation. For carbon steel in an indoor air environment, loss of material due to corrosion during the small percentage of time the system is below normal operating temperature is not an aging effect that requires management. B. The reason why loss of preload is not identified as an aging effect is that Entergy has consistently followed industry guidance (EPRI Report 1010639) in performing aging management reviews. Based on these reviews, loss of preload has not been listed as an aging effect requiring management in the system level aging management review results. While not included in system-level aging management review results, loss of preload is addressed in the Bolting Integrity Program for all bolting within the scope of license renewal except for the reactor vessel closure studs, which are addressed in a separate program. The Bolting Integrity Program is an existing program that addresses loss of preload in accordance with the guidelines of NUREG-1801, Section XI.M18, Bolting Integrity. The program description of LRA Section B.1.2 states that the program applies to all bolting except the reactor head closure studs and includes preventive measures to preclude or minimize loss of preload and cracking. Likewise, loss of material is not an aging effect requiring management for this bolting, but it is also managed by the Bolting Integrity Program. As stated in LRA Section B.1.2, the IP Bolting Integrity Program will be consistent with NUREG-1801 Section XI.M18, which includes measures to manage loss of material and loss of preload. The Bolting Integrity

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	loss of preload due to thermal effects and gasket creep and self loosening for the stated component, material, and environment combination. Explain how these aging effects are not applicable to the bolting in question. If IP is managing this aging effect/mechanism under the other programs, please identify such programs.	Program will apply to all pressure boundary bolting, including the main steam bolting. LRA Table 3.4.1, Item 3.4.1-22 discussion column.will be clarified by inserting the following sentence after "Improper bolting application (design) and maintenance issues are current plant operational concerns and not related to aging effects or mechanisms that require management during the period of extended operation." "Nevertheless, the Bolting Integrity Program manages loss of preload for all bolting in steam and power conversion systems." Also, Table 3.3.1, Item 3.3.1-45 similarly addresses loss of preload, managed by the Bolting Integrity Program. Therefore, LRA Table 3.3.1, Item 3.3.1-45 discussion column will be clarified by inserting the following sentence after "Improper bolting application (design) and maintenance issues are current plant operational concerns and not related to aging effects or mechanisms that require management during the period of extended operation.". "Nevertheless, the Bolting Integrity Program manages loss of preload for all bolting in auxiliary systems." Commitment 2 will be clarified to specifically state the Bolting Integrity Program manages loss of preload and loss of material for all external bolting. Clarification to be incorporated into the LRA.
242	AMR-3.4-7 In LRA Table 3.4.1, Item 3.4.1-11 states in the discussion column that this line item is consistent with NUREG 1801. IP plans to use "Buried Piping and Tanks Inspection" Program to manage "loss of material" aging effect as recommended by the GALL. The GALL Report recommends, under " Further Evaluation Recommended," that detection of aging effects and operating experience are to be further evaluated. Describe the operating experience that IP has in the area of handling buried steel piping, piping components, piping elements, and tanks (with or without coating or wrapping) exposed to soil and how this plant specific and industry operating experience is planned to be evaluated and utilized in the developing this "new" program.	A review of site condition reports back to 2000 revealed that there have been two underground piping leaks that occurred on the auxiliary steam supply cross connect line between Unit 2 and Unit 3. The first leak occurred in 2002 and CR-IP3-2002-04267 was written for this leak. The leak was repaired via the work control process. The second leak occurred in April 2007 and is documented in CR-IP3-2007-01852. This line has been excavated and replaced. The cause of the failure was determined to be advanced corrosion of the pipe due to moisture intrusion. This was caused by the pipe coating breaking down and insulation that was not sufficient for the task. After replacement, the pipe was reinsulated using a special high temperature application moisture resistant material, that was designed to prevent this type of corrosion in the future. This piping is nonsafety-related and not in the scope of license renewal. Copies of the condition reports were provided. No other buried piping repair or replacement was identified during review of operating experience. If trending within the corrective action program or industry operating experience identifies susceptible locations, these areas will be evaluated for the need for additional inspection, alternate coating, or replacement. As stated in Commitment #3, The Buried Piping and Tanks Inspection Program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection.
243	AMR-3.4-8 LRA Table 3.4.1, Item 3.4.1-30, which pertains to steel piping, piping components, and piping elements, exposed to air outdoor (internal) or condensation (internal), has been used by IP for the condensate storage tanks for Units 2 and 3. The vapor space of these tanks is nitrogen blanketed per the discussion provided in the table for this line item. The specific "Note 402" applied to these tanks states that the tank vapor space is conservatively assumed to be condensation. The GALL recommends steel tanks to be managed for " loss of material due to general, pitting and crevice corrosion" under line item number 3.4.1-6. Explain if IP's aging management program for these steel tanks follows the recommendations of the GALL line item 3.4.1-6 also in addition to those of line item 3.4.1-30.	LRA Table 3.4.1, Item 3.4.1-6 also applies to the condensate storage tanks. As indicated in Table 3.4.1, the IP aging management review results follow the recommendations of the GALL Line Item 3.4.1-6 as well as those of Line Item 3.4.1-30. The line for carbon steel tank with treated water (int) environment in Table 3.4.2-3-IP2 and in Table 3.4.2-3-IP3 provides the reference to Item 3.4.1-6.
244	3.5-1 Confirm that all component type/aging effect combinations that credit the SMP for aging management in Tables 3.5.2-1 thru -4 are	All component type/aging effect combinations that credit the Structures Monitoring Program (SMP) for aging management in Tables 3.5.2-1 thru -4 are inspected for designated aging effects, however they are not specifically identified in the scope of the SMP. This is identified as an enhancement to SMP in LRA section B.1.36. ENN-

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	included in the scope of the SMP and are inspected for the designated aging effect. Identify the document(s) available for audit that includes this information.	DC-150 (Condition Monitoring of Maintenance Rule Structures) and previous inspection reports are available on site for review.
245	3.5-2 Why is Note E specified for Table 3.5.2- 1 and 3.5.2-4 line items that reference IWE, IWL, and IWF as the aging management program?	In LRA section B.1.8 and B.1.18 IPEC IWE, IWL, and IWF programs are described as plant- specific programs because the corresponding NUREG-1801 programs (XI.S1, XI.S2, and XI.S3) contain ASME Section XI table and section numbers which change with different editions of the code. The CLB requires that IPEC follow the version of ASME Section referenced in 10CFR50.55(a) and approved for use at IPEC. As this is the case, the IWE, IWL and IWF programs are presented as a plant-specific programs which warrants Note "E" in Table 3.5.2-1 and 3.5.2-4 line items that reference these programs as the aging management program.
246	3.5-3 In Tables 3.5.2-1 thru -4, why are the "Table 1 Item" and "NUREG-1801 Vol. 2 Item" columns blank for all cases where the "Note" column specifies "I, 501"? All of these Table 2 line items have applicable entries for these 2 columns. The implication by leaving them blank is that GALL does not address them. This is not the case. The applicant has taken exception to the GALL "Aging Effects Requiring Management". Revise the 3.5.2 Tables accordingly.	Where aging management review of material/environment combination for IPEC did not identify the aging effect identified by GALL, the aging effect requiring management "AERM" and "Table 1 Item" columns in Tables 3.5.2-1 thru 3.5.2-4 were left blank accordingly. No exception to GALL is taken since there is no aging effect identified. To be conservative, the aging management program(s) were identified to confirm absence of any aging effects. For those cases notes I, 501 are used. Based on past precedents and prior applications, revising 3.5.2 Tables is not necessary.
247	3.5-4 Plant Specific Note 501 states "The IPEC environment is not conducive to the listed aging effects. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation." The Table 2 line items indicate "None" for the aging effects. Does the identified AMP confirm the absence of loss of material, cracking, and change in material properties? Revise the note accordingly.	The identified AMP for those commodities/components will confirm absence of loss of material, cracking, and change in material properties for those commodities/components that may be subject to these aging effects. Based on past precedents and prior applications, revising the note is not necessary.
248	3.5-5 Plant Specific Note 502 states "Loss of insulating characteristics due to insulation degradation is not an aging effect requiring management for insulation material. Insulation products, which are made from fiberglass fiber, calcium silicate, stainless steel, and similar materials, in an air – indoor uncontrolled environment do not experience aging effects that would significantly degrade their ability to insulate as designed. A review of site operating experience identified no aging effects for insulation used at IPEC." Discuss moisture/humidity effects on the insulating characteristics of the insulation material. Discuss the containment internal environment, in the area where the containment insulation is attached. Is the insulation exposed to moisture/humidity? How is this potential aging effect managed?	Indian Point insulation specifications MM92-250 and 9321-01-249-1 Section 3.0 specify that the IP containment insulation is encapsulated. Therefore, the basic insulating material is protected from moisture and humidity. The environmental conditions inside containment are air-indoor uncontrolled defined in LRA Table 3.0-2. IP2 and IP3 have not experienced any aging effect for insulation in this environment, that has caused loss of insulating capability.
249	3.5-6 For Table 1 items 3.5.1-57 and 3.5.1-41, confirm there are no HVAC components that are vibration-isolation mounted in the IP 2/3 LR scope.	Support components for in-scope HVAC are in the scope of license renewal. However, there are no structural vibration isolation elements in scope.
250	3.5-7 In reference to Table 1 item 3.5.1-54, confirm that the IWF program at IP 2/3 currently inspects for loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads, and that IWF will continue to inspect for this condition during the LR period.	The IWF program currently does and will continue during the LR period to inspect for loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads.

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251	3.5-8 In reference to Table 1 item 3.5.1-51, are the nominal yield strengths or the actual yield strengths below 150 ksi? Identify the document(s) available for audit that confirms the actual bolt material strengths.	IPEC structural drawings (available on site for audit) identify use of A-325 bolts. These bolts have actual yield strength below 150 ksi (e.g., ref. Test Report ME-3842 available on site for audit).
252	3.5-9 In reference to Table 1 item 3.5.1-48, describe the materials of construction for all water control structures in the IP 2/3 LR scope. Are there earthen intake and discharge canals? Does Entergy conduct 5-year underwater inspections of these structures?	The materials of construction for in-scope water control structures are described in Section 3.5.2.1.2 of the LRA. There are no earthen intake or discharge canals at IP 2/3. Entergy does not perform 5-year underwater inspections of water control structures (Reference response to question 88 for LR period).
253	3.5-10 In reference to Table 1 item 3.5.1-34, are any water control structures in the IP 2/3 LR scope exposed to raw service water (ultimate heat sink)? How is increase in porosity and permeability, cracking, and loss of material due to aggressive chemical attack managed for these structures? Does Entergy conduct 5-year underwater inspections of these structures?	Water control structures at IP 2/3 are exposed to the raw water from Hudson River through which the service water system draws it water as the 'ultimate heat sink' source. Due to absence of aggressive environment, increase in porosity and permeability, cracking, and loss of material due to aggressive chemical attack are not identified as an aging effect requiring management. However, as addressed in Section 3.5.2.1.2 of the LRA, SMP will continue to confirm absence of these aging effects. Entergy does not perform 5-year underwater inspections of water control structures. However, consistent with the response to audit question 88, commitment 25 includes an enhancement to 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.
254	3.5-11 In reference to Table 1 item 3.5.1-32, why is SMP not credited for accessible areas? Does IP 2/3 meet the criteria in ACI 201.2R-77? If not, how are inaccessible areas managed for aging?	As provided in the discussion section for item 3.5.1-32, increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide are not aging effects requiring management for IPEC. Thus, SMP is not credited. IP 2/3 meet the requirements of ACI 201.2R-77 as discussed in Section 3.5.2.2.2 of the LRA. However, structures monitoring program (SMP) will continue to monitor for such aging effects.
255	3.5-12 In reference to Table 1 item 3.5.1-31, why is SMP not credited for accessible areas? Does IP 2/3 meet the groundwater criteria for a non-aggressive environment? Does IP 2/3 have a program for sampling of below-grade concrete for signs of degradation? Provide the details of the program.	With reference to Table 1 Item 3.5.1-31, as stated in the discussion there is no aging effect requiring management, however the additional discussion provided in Section 3.5.2.2.2.1 of the LRA does identify the SMP to confirm absence of any aging effects. IP 2/3 meet the groundwater criteria for non-aggressive environment as addressed in Section 3.5.2.2.2.4 of the LRA. The Structures Monitoring Program identifies opportunistic inspections for below grade concrete when they become accessible. Guidance will be added to the Structures Monitoring Program to inspect inaccessible concrete areas that are exposed by excavation for any reason. Further details of the Structures Monitoring Program are provided in LRA Section B.1.36 including references to applicable details in NUREG-1801, Section XI.S6, and in the on-site program bases documentation.
256	3.5-13 In reference to Table 1 items 3.5.1-23,-24,-26,-27, why is the phrase "except Group 6" included here, considering that the SMP is being credited for managing aging of Group 6 structures?	Since the Table 1 Items 3.5.1-23,-24,-26,-27 column description 'Component' (provided by GALL) contains this exception, and since Group 6 concrete is addressed in Table 1 Items 3.5.1-34 through 3.5.1-37, the discussion for these line items includes this exception. The intent was to address Group 6 in the discussion for Items 3.5.1-34 through 3.5.1-37. In this case, the discussion is essentially the same, so the phrase "except for Group 6" could have been omitted.
257	3.5-14 In reference to Table 1 item 3.5.1-26, is IP 2/3 located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) ? If so, why is freeze-thaw not applicable?	IP2/3 is located in a moderate to severe weathering conditions (weathering index >100 day-inch/yr), however freeze-thaw damage is not significant for reinforced concrete provided that the concrete mix design meets the air content (entrained air 3 6%) and water-to-cement ratio (0.35-0.45) specified in ACI 318 0r ACI 349. For IPEC these conditions are satisfied and therefore freeze-thaw is not an aging effect requiring management. However, structures monitoring program (SMP) will continue to monitor for such aging effects.
258	3.5-15 In reference to Table 1 item 3.5.1-6, IWE should be credited instead of IWL. Please correct.	Table 1 Item 3.5.1-6 reference to "IWL" will be changed to "IWE". Clarification to be added to the LRA.
264	3.6-1 Provide an AMR for long-lived components and structures for the revised secondary SBO recovery	The LRA figures 2.5-2 and 2.5-3 were revised to add the secondary off-site power path that was credited for GDC-17. (Reference Audit Question #1) The IP2 secondary off-site power path includes medium voltage cable from the 6.9 kV bus 5

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	path. This path is from the switchyard circuit breakers to onsite electrical distribution system including the associated control circuits and structures.	and 6 to the Buchanan substation breaker F2-3 via the IP2 13.8kV/6.9kV GT auto transformer and the IP2 13.8kV switchgear. The IP3 secondary off-site power path includes metal-enclosed (switchgear) bus and medium voltage cable from the 6.9 kV bus 5 and 6 to the Buchanan substation breaker F3-1 via the IP3 13.8kV/6.9kV GT auto transformer and the IP3 13.8kV switchgear. The aging management review results for components in the IP2 and IP3 secondary SBO recovery path are included in Table 3.6.2-1, for "Inaccessible medium voltage (2kV to 35kV) cables (e.g., installed underground in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements." The auto transformer and the 13.8kV switchgear are active components, and are not subject to aging management review. The on-site electrical AMR documents the medium-voltage cables for the IP2 secondary off-site power path included in the aging management review of IP2 medium-voltage cables. The underground portions of these cables are included in the Non-EQ Inaccessible Medium-Voltage Cable Program described in LRA Section B.1.23. Control cables associated with the switchyard breakers were included as electrical commodities. The structures (duct banks and manholes) associated with these cables are included in Section 3.5, Table 3.5.2-3 of the LRA. The on-site electrical AMR documents the medium-voltage cables for the IP3 secondary off-site power path were included in the aging management review of IP2 and IP3 medium-voltage cables. The underground portions of these cables are included in the Non-EQ Inaccessible Medium-Voltage Cable Program described in LRA section B.1.23. Control cables associated with the switchyard breakers were included as electrical commodities. The structures (duct banks and manholes) associated with these cables are included in Section 3.5, Table 3.5.2-3 of the LRA.
265	3.6-2 In LRA, Table 3.6.2-1, under Transmission conductors and connections for SBO recovery, you have stated that no aging effects requiring management and no AMP is required. You have also stated that the IPEC transmission conductors subject to AMR were bounded by the Ontario Hydro test. NUREG 1800, Rev. 1, Section 3.6.2.2.3 identifies loss of conductor strength due to corrosion is the aging effect of high voltage transmission conductor. Explain in detail how the test conducted by Ontario Hydro study is valid for your plant. Include plant specific acceptance criteria for transmission conductor strength in your response.	Indian Point LRA Section 3.6.2.2.3 is the further evaluation section for transmission conductors. This section provides the evaluation for the aging effect loss of conductor strength due to corrosion of transmission conductors. The conclusion of this section is there are no aging effects requiring management for transmission conductors or connectors. The most prevalent mechanism contributing to loss of conductor strength of an ACSR (aluminum conductor steel reinforced) transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. As stated in this LRA section, corrosion in ACSR conductors is a very slow-acting mechanism and the corrosion rates depend largely on air quality, which includes suspended particles chemistry, SO2 concentration in air, precipitation, fog chemistry, and meteorological conditions. Air quality in rural areas generally contains low concentrations of suspended particles and SO2, which keeps the corrosion rate to a minimum. Although IPEC is located near urban areas there are no other industries in the immediate rural area. Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion. The IP2 and IP3 transmission cables for the 138 kV offsite power recovery are 1172 MCM ACAR (aluminum conductor aluminum reinforced) 30/7 or 18/19 overhead transmission conductors. This specific conductor type was not included in the Ontario Hydroelectric test, but these types are bounded by types that are included. The IP2 and IP3 transmission cables are bounded, because of the conductor size, configuration, and support strand material. The IP2 and IP3 transmission cables have aluminum reinforcing strands, so the corrosion would be bounded by the Ontario Hydroelectric ACSR transmission cables. There is a set percentage of composite conductor strength established at which a transmission conductor is replaced. As illustrated in the following, there is ample strength margin to maintain the transmission conductor intended function through the period of extended operation. The IP2 and IP3 conductor types are bounded by the following example, which is a conservative example from the Ontario Hydroelectric test based on ultimate conductor strength and strand configuration. The National Electrical Safety Code (NESC) requires that tension on installed conductors be a

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		maximum of 60% of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind and temperature. These requirements are reviewed concerning the specific conductors included in the aging management review. The conductors with the smallest ultimate strength margin (4/0 ACSR) will be used as an illustration of this strength margin. The ultimate strength and the NESC heavy load tension requirements of 4/0 (212 MCM) ACSR are 8350 lbs. and 2761 lbs. respectively. This heavy load tension is 33% of the ultimate strength, which is within the 60% requirement. The margin between the NESC Heavy Load and the ultimate strength is 5589 lb.; i.e., there is a 67% of ultimate strength margin. The Ontario Hydroelectric study showed a 30% loss of composite conductor strength in an 80 year old conductor due to corrosion. In the case of the 4/0 ACSR transmission conductors, a 30% loss of ultimate strength would mean that there would still be a 37% ultimate strength margin between what is required by the NESC and the actual conductor strength. The 4/0 ACSR conductors have the lowest initial design margin of transmission conductors included in the NESC. This illustrates with reasonable assurance that transmission conductors will have ample strength through the period of extended operation. There are no applicable aging effects that could cause loss of the intended function of the transmission conductors for the period of extended operation. There are no applicable aging effects requiring management for the IP2 and IP3 transmission conductors.
266	3.6-3 In LRA, Table 3.6.2-1, under 138 kV direct buried insulated transmission cable, you have stated that no aging effect requiring management and no AMP is required. You also states through Note 602 that based on vendor information, this transmission cable is not subject to water treeing, since it is designed for continuously wet conditions. Address the following: a. How is positive oil pressure maintained in the pot heads to prevent any moisture intrusion? B. How is the property of the oil in the pot head maintained to the manufacturer's specifications? C. Provide details of periodic visual inspections and walk down performed and proposal for monitoring for oil leakage including checking tightness of the pothead bolted connections. D. Provide manufacturer specifications that this cable is qualified for continuously wet conditions.	a.) The 138kV direct buried transmission cable is a solid dielectric cable and the end electrical connections are enclosed in an oil-filled pothead. The pothead is a sealed component filled with oil pressurized with a local nitrogen tank and continuously monitored by a pressure switch with alarm. b.) The oil in the pothead prevents moisture and oxygen intrusion into the connection, but does not contribute to the basic impulse level (BIL) rating for the pothead nor does the oil provide insulation for the connection. Therefore, the oil does not require a specific dielectric strength to support the connection intended function. Also the pothead is sealed, so opening the pothead to test the oil would increase the risk of introducing oxygen and moisture into the pothead. The pothead prevents moisture and oxygen from affecting the connection, so corrosion is not an applicable aging effect for the connection. Routine maintenance and continuous pressure monitoring provide assurance that the pothead remains sealed, so there are no electrical connection aging effects that require management. Routine maintenance includes periodic visual inspections of the pothead seals and the nitrogen pressure system. The mechanical portions of the oil-filled pothead components provide a nitrogen source for the oil-filled pothead with a high/low pressure alarm. The function of these components is to provide an oxygen and moisture barrier for the connection inside the pothead. The pothead is pressurized with nitrogen to prevent moisture and oxygen intrusion, and a continuous pressure alarm monitors the pressure. Routine maintenance includes periodic visual inspections of the pothead seals and continous monitoring of the nitrogen pressure will ensure deficiencies are identified. c.) Routine maintenance includes periodic visual inspections of the potheads including the seal between the pothead and the 138 kV solid dielectric cables, and between the pothead and the nitrogen connections. In addition, the pressure of the pothead and the nitrogen system is continuously monitored with an alarm in the substation control room. Routine maintenance does not check the tightness of the pothead bolting, since the pothead is not accessible when the 138kV line is energized. The periodic visual inspections are performed at least once per year. This visual inspection combined with the continuous monitoring will ensure an environment is maintained to preclude moisture and oxygen. Maintenance procedure 0-HVE-401-ELC, Visual Inspection of 138KV and 345 KV Electrical Distribution Equipment, will be revised to clarify that the pothead seal will be visually inspected for leakage and possible degradation to preclude loss of intended function.

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		d.) Refer to AMP audit question (Item #2). The 750 MCM 138kV solid dielectric cable is constructed with XLPE insulation, a 0.125 inch lead sheath, and an overall extruded PE jacket. Based on the manufacturer specification, the extruded lead alloy sheath provides waterproofing guaranteed by the manufacturing process. This is in accordance with the purchase specification that required the cable to be supplied with a moisture barrier.
267	3.2-1 Numerous line items in Tables 3.2.2-1-IP2 and 3.2.2-1-IP3 (RHR System) credit TLAA- Metal Fatigue to manage the aging effect of metal fatigue (cumulative fatigue damage). These line items also indicate that the evaluation of the TLAA is addressed in Section 4.3 of the LRA. However, it appears that the writeup in Section 4.3 does not cover the discussion for most components, such as flex hose, flow elements, thermowell, tubing, and valve bodies. Please explain the discrepancy.	□The components identified, with the exception of flex hoses, are all considered part of the "piping and in-line components" line item identified in LRA Tables 4.1-1 and 4.1-2 and as such are evaluated as part of the system. ASME B31.1 stress analysis is performed as required for the RHR system. This approach is consistent with the approach taken in the Pilgrim Nuclear Power Station license renewal application as described in Amendment 8 to the PNPS LRA dated 9/13/06. The TLAA-metal fatigue entry in the AMP column indicates that the applicable TLAA is addressed in LRA Section 4.3. These components are addressed by the 7000 cycle discussion in LRA Section 4.3.2 and further details are provided in section 3 of the TLAA-Mechanical Fatigue report IP-RPT-06-LRD04. These sections conclude that the TLAA remains valid, so no aging management program is necessary. The flex hoses should not be included as part of the TLAA evaluation since they isolate portions of the system from each other and would not be part of a specific stress analysis for the system or parts of the system. The line items for the flex hose in the RHR system in Tables 3.2.2-1-IP2 and 3.2.2-1-IP3 that identify TLAA-Metal Fatigue will be removed. Clarification to be incorporated into the LRA
268	3.2-2 While IP3 has two line items in Table 3.2.2-2 (Containment Spray System) and Table 3.2.2-4 (Safety Injection Systems), which correspond to GALL V.D1-26, Piping, Piping Components and Piping Elements. These line items reference Table 1 item 3.2.1-4. Please explain why IP2 does not have similar items. Why is the buried piping and tanks program adequate for managing aging effect of loss of material due to pitting and crevice corrosion?	GALL V.D1-26 is for buried piping. While the IP3 configuration of this piping includes a section of buried piping exposed to soil, the IP2 piping configuration for these systems does not include buried piping exposed to soil. The Buried Piping and Tanks Program is consistent with the GALL program and includes surveillance and preventive measures to manage loss of material due to corrosion by protecting the external surface of buried carbon steel piping and tanks.
269	3.2-3 Both IP2 and IP3 have two line items in Table 3.2.2-5 (Containment Penetrations System) reference Table 1 item 3.2.1-8. Describe how One-Time Inspection will be performed on these components. Specifically, please discuss the parameters to be monitored and the inspection techniques that will be utilized. Please also justify why One-Time Inspection Program alone is sufficient to manage the aging effect of loss of material due to pitting and crevice corrosion.	The One-Time Inspection Program will confirm that loss of material is not occurring or is insignificant for internal stainless steel surfaces exposed to condensation in ESF systems. This program uses visual and other NDE techniques to confirm that loss of material is not occurring or is so insignificant that an aging management program for these components is not warranted. In the containment penetration system, this program applies to the internal surfaces of stainless steel piping and valve bodies in the containment penetration for gas analyzers. Parameter to be monitored or inspected is wall thickness. Inspection techniques will be visual (VT-1 or equivalent) or volumetric (RT or UT) inspection. The normal internal environment for the gas analyzers is air/gas with material of stainless steel and no aging effects. Since condensation may be possible a one-time inspection was conservatively included to verify that unacceptable pitting and crevice corrosion, although not expected, is not occurring, thereby confirming that there is no need for an ongoing aging management program for the period of extended operation. As specified in the One-Time Inspection Program, unacceptable inspection findings will be evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections and for monitoring and trending the results.
270	3.2-4 The "Discussion Column" of LRA Table 1 Item 3.2.1-24 states that loss of preload is a design-driven effect and this aging effect needs not be considered. Thus, no associated Table 2 line items were included in the IP LRA. Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications, however, loss of preload could also due to other effects such as gasket creep and self-	The EPRI Mechanical Tools (EPRI 1010639) was the primary industry guideline used in performing aging management reviews for mechanical equipment. The Mechanical Tools document is based on industry-wide operating experience. Gasket creep and self-loosening are mechanisms that could lead to loss of preload for steel closure bolting, but are not considered aging mechanisms. Operating experience indicates that these mechanisms occur in relatively short order in applications with improper bolted joint design or installation. Operating experience at IPEC was evaluated to determine if there have been instances in which mechanical component failure was attributable to loss of preload. The review of IPEC operating experience did not identify instances in which mechanical component failure was attributable to loss of

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	loosening. Please justify why other effects are not applicable. In addition, loss of preload in bolting is listed as an aging effect in the GALL Report, which credits the Bolting Integrity Program for managing this effect. Please justify why the applicant's Bolting Integrity Program (B.1.2) did not take exception to the GALL Report, given that loss of preload is not considered an aging effect in IP.	pressure boundary bolting preload. This is consistent with the EPRI Mechanical Tools (Appendix F, Section 3.1) that do not consider loss of preload an aging effect for bolted closures. Gasket creep will normally occur shortly after initial loading, which allows for addressing this mechanism by installation practices and subsequent maintenance of the joint. Self-loosening is also not an aging mechanism but is an event-driven mechanism that occurs due to improper joint design or installation that doesn't properly consider the potential for this mechanism. This would also be detected early in component service life and actions would be taken to prevent recurrence. The Bolting Integrity Program is an existing program that relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, industry recommendations, and Electric Power Research Institute (EPRI) NP-5769, with the exceptions noted in NUREG-1339 for safety-related bolting. As stated in LRA Section B.1.2, the program applies to bolting and torquing practices of safety- and nonsafety-related bolting for pressure retaining components, NSSS component supports, and structural joints. The program addresses all bolting regardless of size except reactor head closure studs, which are addressed by the Reactor Head Closure Studs Program. The program relies on industry recommendations for comprehensive bolting maintenance, as delineated in EPRI TR-104213 for pressure retaining bolting and structural bolting. The Bolting Integrity Program also includes preventive measures to preclude or minimize loss of preload, which is consistent with the GALL report so an exception to the GALL program description was not required. In summary, Entergy has consistently followed industry guidance (EPRI Report 1010639) in performing aging management reviews. Based on these reviews, loss of preload has not been listed as an aging effect requiring management in the system level aging management review results. While not included in system-level aging management review results, loss of preload is addressed in the Bolting Integrity Program for all bolting within the scope of license renewal except for the reactor vessel closure studs, which are addressed in a separate program. The Bolting Integrity Program is an existing program that manages loss of preload in accordance with the guidelines of NUREG-1801, Section XI.M18, Bolting Integrity. LRA Table 3.2.1, Item 3.2.1-24 discussion column will be clarified by inserting the following sentence after "Improper bolting application (design) and maintenance issues are current plant operational concerns and not related to aging effects or mechanisms that require management during the period of extended operation." "Nevertheless, the Bolting Integrity Program manages loss of preload for all bolting in ESF systems." Commitment 2 will be clarified to specifically state the Bolting Integrity Program manages loss of preload and loss of material for all external bolting. Clarification to be incorporated into the LRA.
271	3.2-5 The "Discussion Column" of LRA Table 1 Items 3.2.1-25 and 26, state that these two line items are not applicable. Does IP has bearing and lube oil coolers and associated piping that are considered part of the ESF systems? What are the operating temperatures for these components. If these components were not included in the ESF system, where were they being addressed at?	Items 3.2.1-25 and 3.2.1-26 apply to piping, piping components, and piping elements exposed to closed cycle cooling water; not to the coolers. IP2 and IP3 have seal, lube oil and motor coolers that are treated as part of the ESF systems and are subject to aging management review. The associated supply and return piping exposed to closed cycle cooling water is addressed with the closed cooling water system in Tables 3.3.2-3-IP2/IP3. The operating temperatures are <140°F (typically 70 to 125°F) for the closed cooling water system supplies to the ESF seal, lube oil and motor coolers. The ESF seal, lube oil and motor coolers are addressed in LRA Tables 3.2.2-1-IP2/IP3 for the residual heat removal system and Tables 3.2.2-4-IP2/IP3 for the safety injection system.
272	3.2-6 The "Discussion Column" of LRA Table 1 Items 3.2.1-32, states that "The Fire Protection and Periodic Surveillance and Preventive Maintenance Programs/ External Surface Monitoring manage loss of carbon steel components by periodic visual inspection of component internal surfaces." Please elaborate how "Fire Protection Program" would manage loss of material and explain why the associated Table 2 line items didn't credit this?	As indicated in the associated Table 2 line items, either the Fire Protection Program or the Periodic Surveillance and Preventive Maintenance Programs manage loss of material of carbon steel components by periodic visual inspection of component internal surfaces. One or the other program is adequate; both programs are not necessary. Table 3.3.2-12-IP2 and Table 3.3.2-12-IP3 include line items referring to Item 3.2.1-32 and crediting the Fire Protection Program. The associated components are part of the Halon or carbon dioxide gaseous fire protection systems. The specific components referencing Item 3.2.1-32 are distribution header components that are open to atmosphere resulting in an indoor air internal environment. The Fire Protection Program manages loss of material for external carbon steel

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	Please also compare the heat exchanger (housing) inspection frequency difference between the "Periodic Surveillance and Preventive Maintenance Program," proposed by IP and " External Surfaces Monitoring," recommended by the GALL Report.	components by visual inspection of external surfaces. The IP2 cable spreading room Halon fire suppression system is visually inspected under the Fire Protection Program. The IP3 cable spreading room, 480V switchgear room, and EDG room CO2 fire suppression system is visually inspected under the Fire Protection Program. For systems where internal carbon steel surfaces are exposed to the same environment as external surfaces, external surfaces will be representative of internal surfaces. Thus, loss of material on internal carbon steel surfaces is also managed by the Fire Protection Program. Table 2 items that refer to Table 1 Item 3.2.1-32 credit the PSPM for internal surfaces of carbon steel heat exchanger (housing) with an environment of indoor-air. The Periodic Surveillance and Preventive Maintenance Program inspections are performed at least once per 5 years. Loss of material due to corrosion is a long-term aging effect for carbon steel components exposed to air-indoor (int). The affected components have been in service for the life of the plant without significant corrosion. Based on the slow acting aging mechanism as confirmed by plant operating experience, the inspection frequency of at least once per 5 years is sufficient. The intervals of inspections may be adjusted, as necessary, based on inspection experience. The GALL program "Inspection of Internal Surfaces and Miscellaneous Piping and Duct Components" includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. Locations are chosen to include conditions likely to exhibit these aging effects and inspection intervals are established such that they provide timely detection of degradation. Based on the inspection interval of five years and applicable program arameters, the PSPM Program is an acceptable alternative to the Inspection of Internal Surfaces and Miscellaneous Piping and Duct Components Program.
273	3.2-7 Regarding Table 1 Items 3.2.1-37: please explain why "Periodic Surveillance and Preventive Maintenance Program" is equivalent to GALL recommended AMP (Open-Cycle Cooling Water System) for managing aging effect of loss of material for containment sump piping and valve body (GALL Report item (V.D-25).	The GALL recommended AMP (XI.M20 Open-Cycle Cooling Water System) is not applicable for the containment sump water environment, which is considered raw water due to the various substances that can be entrained as fluids drain to the sump. This creates a fundamentally different environment than the service water environment described in GL 89-13, which is the basis for the XI.M20 program in GALL. The Periodic Surveillance and Preventive Maintenance Program includes periodic visual inspections similar to those employed in XI.M20.
274	3.2-8 The "Discussion Column" of LRA Table 1 Items 3.2.1-50 states that this line item is consistent with the GALL Report. Explain why no associated Table 2 line items is liked to this Table 1 line item?	This line item covers aluminum exposed to air – indoor uncontrolled and requires no aging management program. Links from Table 2 do exist, however. Tables 3.2.2-3-IP2, 3.3.2-4-IP2, 3.3.2-8-IP2/3, 3.3.2-10-IP2/3, 3.3.2-12-IP3, 3.3.2-19-22-IP2 link to Item 3.2.1-50.
275	3.2-9 IP2 and IP3 both have two line items of bolting (one in RHR system and the other in Containment Spray system) that reference Table 1 line item 3.2.1-57. These bolting have "pressure boundary" intended function. Please explain why "Bolting Integrity Program" is not credited for these bolting?	The bolting that references Table 3.2.1 line item 3.2.1-57 for in RHR system and the Containment Spray system is stainless steel bolting that is exposed to an environment of indoor air. There are no aging effects requiring management for stainless steel exposed to indoor air. This is consistent with Table 2, Item 57 in NUREG-1801, Volume 1. Since there are no aging effects requiring management, the bolting integrity program is not identified for these bolts (program "None"). Although no aging effects requiring management were identified, the Bolting Integrity Program does apply to this bolting. The Bolting Integrity Program description of LRA Section B.1.2 states that the program applies to all bolting except the reactor head closure studs. As stated in LRA Section B.1.2, the IP Bolting Integrity Program will be consistent with NUREG-1801 Section XI.M18.
281	A certification should be included in the LRA that the following verifications with respect to this aging management program (AMP B.1.27) are documented on-site in an auditable form: 1. The plant aging management program AMP B.1.27, One Time Inspection Program, contains all elements of NUREG-1801, Rev. 1, AMP XI.M32 2. The conditions at the plant are bounded by the conditions for which the GALL AMP (XI.M32) was evaluated	1. The AMP B.1.27 One-Time Inspection Program contains all 10 elements of the NUREG-1801 Rev. 1 program XI.M32. This 10 element comparison is available in Report IP-RPT-06-LRD07 in Section 3.2, which is available on site for review. 2. The IPEC One-Time Inspection Program, as well as the XI.M32 program in NUREG-1801, are credited for various materials and environments to confirm the effectiveness of other aging management programs such as Water Chemistry, Diesel Fuel Monitoring and Lube Oil Analysis and to address concerns for potentially long incubation periods for certain aging effects on structures and components. There are cases where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. For these cases, there will be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly such that an ongoing aging management program is not necessary to ensure the component or structure intended function. This is consistent with XI.M32 program description which states:

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		"Situations in which additional confirmation is appropriate include (a) an aging effect is not expected to occur but the data is insufficient to rule it out with reasonable confidence; (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected; or (c) the characteristics of the aging effect include a long incubation period. For these cases, there is to be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation." Therefore, the IPEC One-Time Inspection Program addresses the same types of conditions as those for which the XI.M32 program in NUREG-1801 was evaluated. The comparisons with XI.M32 are available in report IP-RPT-06-LRD07 in Section 3.2, which is available on site for review.
282	What specific components are associated with Heat Exchangers (tubes) with the aging effect of "fouling" that contain "Note G" from the following LRA pages: 3.2-33 3.2-39 3.2-63 3.2-64 3.2-74 3.2-75	The components associated with Heat Exchangers (tubes) with the aging effect of "fouling" that contain "Note G" are as follows; 3.2-33 IP2 RHR Heat Exchangers and the RHR Pump Seal Coolers 3.2-39 IP3 RHR Heat Exchangers and the RHR Pump Seal Coolers 3.2-63 IP2 Recirculation Pump Motor Coolers 3.2-64 IP2 Safety Injection Pump Seal Cooler Heat Exchanger 3.2-74 IP3 Recirculation Pump Motor Coolers 3.2-75 IP3 Safety Injection Pump Seal Cooler Heat Exchanger
352	AMR 3.2 For IP2, LRA pages 3.2-44 to 46, 3.2-65, 3.2-69 to 70 and 3.2-83 to 86, contain sixteen line items that specify the Aging Management Program is NONE and the Aging Effect is NONE with a Note G. Please identify the specific component that is being referenced in each line item. Provide the justification used to make the determination that the Aging Effect is NONE.	The line items in question refer to stainless steel and copper alloy components exposed to indoor air on the internal surface. The component type line item for flow element on page 3.2-44 refers to the containment spray header flow elements (FE-945A/B). The component type line item for nozzle on page 3.2-44 refers to the containment spray header flow nozzles. The component type line item for piping on page 3.2-45 refers to the containment spray header piping. The component type line item for tubing on page 3.2-46 refers to the tubing for the containment spray header flow transmitters. The component type line item for valve body on page 3.2-46 refers to the containment spray header drain valves (S51A/B). The component type line item for piping on page 3.2-65 refers to the containment pressure sensing lines. The component type line item for tubing on page 3.2-69 refers to the containment pressure sensing lines tubing. The component type line item for valve body on page 3.2-70 refers to the containment pressure sensing line valves. The component type line item for flow element on page 3.2-83 refers to the radiation monitor flow element (FE-41-42). The two component type line items for piping on page 3.2-84 refers to containment penetration piping containing indoor air. The component type line item for regulator on page 3.2-85 refers to the regulator valve for the radiation monitor (PRV-41-42). The component type line item for sampler housing on page 3.2-85 refers to the *sampler housings for the radiation monitor* (R-41/42). The component type line tubing on page 3.2-85 refers to the tubing for the radiation monitor instruments (R-41/42). The two component type line items for valve body on page 3.2-86 refers to various valve bodies in containment penetrations. This environment of indoor air in the LRA is consistent with the air- indoor uncontrolled environment defined in NUREG-1801 Vol. 2. However NUREG-1801 Vol. 2 does not have air – indoor uncontrolled as an internal environment, therefore, note G was used indicating the environment is not in NUREG-1801. Stainless steel and copper alloy are highly corrosion resistant materials in indoor air that, in accordance with the EPRI Mechanical Tools, does not experience aging effects in a dry indoor environment. The environment of indoor air in the LRA is uncontrolled air above the dew point that will rarely if ever experience condensation on the surface of the component. Without significant moisture, stainless steel and copper alloy will not experience aging effects. This is consistent with the NUREG-1801 air – indoor uncontrolled (external) line items for stainless steel (V.F-12) and for copper alloy (V.F-3) which show no aging effects.

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353	AMR 3.2 For IP3, LRA pages 3.2-47 to 48, 3.2-50, 3.2-76, 3.2-80 to 81, 3.2-87 and 3.2-89, contain nine line items that specify the Aging Management Program is NONE and the Aging Effect is NONE with a Note G. Please identify the specific component that is being referenced in each line item. Provide the justification used to make the determination that the Aging Effect is NONE.	The line items in question refer to stainless steel components exposed to indoor air on the internal surface. The component type line item for flow element on page 3.2-47 refers to the containment spray header flow elements (FE-945A/B). The component type line item for nozzle on page 3.2-48 refers to the containment spray header flow nozzles. The component type line item for piping on page 3.2-48 refers to the containment spray header piping. The component type line item for tubing on page 3.2-50 refers to the tubing for the containment spray header flow transmitters. The component type line item for piping on page 3.2-76 refers to the containment pressure sensing lines. The component type line item for tubing on page 3.2-80 refers to the containment pressure sensing lines tubing. The component type line item for valve body on page 3.2-81 refers to the containment pressure sensing line valves. The component type line item for piping on page 3.2-87 refers to containment penetration piping containing indoor air. The two component type line items for valve body on page 3.2-89 refers to various valve bodies in containment penetrations. This environment of indoor air in the LRA is consistent with the air - indoor uncontrolled environment defined in NUREG-1801 Vol. 2. However NUREG-1801 Vol. 2 does not have air – indoor uncontrolled as an internal environment, therefore, note G was used indicating the environment is not in NUREG-1801. Stainless steel is a highly corrosion resistant material in indoor air that, in accordance with the EPRI Mechanical Tools, does not experience aging effects in a dry indoor environment. The environment of indoor air in the LRA is uncontrolled air above the dew point that will rarely if ever experience condensation on the surface of the component. Without significant moisture, stainless steel will not experience aging effects. This is consistent with the NUREG-1801 air – indoor uncontrolled (external) line item for stainless steel (V.F-12) which shows no aging effects.
354	AMR 3.2 For IP2, on LRA pages 3.2-34 and 3.2-64, the loss of material due to wear in stainless steel and copper alloy, respectively, for external treated water heat exchanger tube components is managed by the Heat Exchanger Monitoring Program with a Note H. How does this program manage the aging effects for these material and environment?	In accordance with Appendix B.1.17, the Heat Exchanger Monitoring Program includes periodic visual or non-destructive examinations to detect loss of material due to wear on the outside tube surfaces.
355	AMR 3.2 For IP3, on LRA pages 3.2-39 and 3.2-75, the loss of material due to wear in stainless steel and copper alloy, respectively, for external treated water heat exchanger tube components is managed by the Heat Exchanger Monitoring Program with a Note H. How does this program manage the aging effects for these material and environment?	In accordance with Appendix B.1.17 the Heat Exchanger Monitoring Program includes periodic visual or non-destructive examinations to detect loss of material due to wear on the outside tube surfaces.
356	AMR 3.2 For IP3, LRA pages 3.2-48 to 51 contain eleven line items that have reference to Note G and plant specific Note 202. Note G states the environment is not in NUREG-1801 for this component and material. Note 202 states that the treated water environment contains sodium hydroxide. Explain how the Aging Management Program listed in each line item will manage the aging effects for the material and environment for the specified component?	Per audit items 90 and 91, components exposed to sodium hydroxide are managed by the Periodic Surveillance and Preventive Maintenance Program. The LRA line items in Table 3.2.2-2-IP3 will be revised to replace the Water Chemistry Control – Auxiliary Systems with Periodic Surveillance and Preventive Maintenance (PSPM) as the aging management program for components with Notes G and 202. The PSPM program will perform visual or other NDE inspections on the inside surfaces of a representative sample of stainless steel components exposed to sodium hydroxide once every five years to manage loss of material and cracking. Clarification to be incorporated into the LRA.
357	In LRA Table 3.1.1, item 3.1.1-68, Entergy states, "The Water Chemistry Control - Primary and Secondary and Inservice Inspection Programs manage cracking in most stainless steel and steel with stainless steel clad Class 1 components. For some componenets not subject to the Inservice	LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 will be revised to credit the Inservice Inspection Program in addition to the Water Chemistry Control – Primary and Secondary Program to manage cracking of stainless steel primary manway cover insert plate. Information to be added to the LRA.

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	Inspection Program, the Water Chemistry Control - Primary and Secondary Program manages cracking". For the SG manway cover insert plate, a pressure boundary SS component in LRA Table 3.1.2-4 for both IP2 nad IP3, Entergy credits water chaemistry control - primary and secondary AMP and refers to the Table 1 item 3.1.1-68 [Table 2 item IV.D1-1 (R-07)] to manage cracking. Since this is a pressure boundary component; the ISI program should be added to the water chemistry control program. This is inconsistent with GALL recommendations as well as the LRA Table 1 discussion for 3.1.1-68. Clarify this discrepancy.	