ENT000380
Submitted: March 30, 2012

Entergy

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Fred Dacimo
Vice President
License Renewal

March 24, 2008

Re: Indian Point Units 2 & 3
Docket Nos. 50-247 & 50-286
NL-08-057

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 3 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 3 of the License Renewal Application (LRA), which consists of five attachments. Attachment 1 consists of an amendment to the LRA to address Regional Inspection items. Attachment 2 consists of an amendment to address Audit Time Limited Aging

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NRR

Analyses (TLAA) and other LRA amendment items. Attachment 3 consists of a revision to the list of regulatory commitments associated with the LRA. Attachment 4 provides the responses to the questions raised by the NRC team during the TLAA portion of the LRA. Attachment 5 provides the responses to the questions raised by the NRC team during the Aging Management Programs (AMP) portion of the LRA.

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 3/24/08.

Sincerely,

Fred R. Dacimo
Vice President
License Renewal

Attachments:

1. Regional Inspection LRA Amendment
2. Audit TLAA and other LRA Amendment
3. IPEC LRA List of Regulatory Commitments, Revision 4
4. TLAA Audit Database Report
5. AMP Audit Database Report

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

ATTACHMENT 1 TO NL-08-057

Regional Inspection LRA Amendment

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

NRC Regional Inspection
License Renewal Application
Amendment

Based on discussions with the staff during the NRC inspection, the LRA is revised as described below. (underline – added, strikethrough – deleted)

Components installed to improve the flow of water to the service water pump suction are added to the scope of license renewal and require the following LRA changes.

LRA Section 2.4.2, Water Control Structures, Description, *Intake Structure*, sixth paragraph, is revised as follows.

For both Unit 2 and Unit 3, the intake structure is a massive reinforced concrete structure, consisting of separate concrete cells. The base of the structure is founded on rock and the exterior walls of the structure are reinforced concrete. The service water strainer pit is a reinforced concrete structure with the west wall being common to the intake structure. The pit is covered with steel decking supported on I-beams. The service water bay enclosure consists of structural steel framing and grating. The Unit 3 service water pump bays are supplied with fiberglass baffling/grating partitions installed to improve the flow of water to the pump suction and reduce hydraulic interaction between the pumps.

LRA Table 2.4-2, Water Control Structures Components Subject to Aging Management Review, *Steel and Other Metals*, is revised to add the following line item.

Component	Intended Function
Steel and Other Metals	
Baffling/grating partition and support platform (steel portion)	Support for Criterion (a)(2) equipment

Component	Intended Function
Other Materials	
Baffling/grating partition and support platform (fiberglass portion)	Support for Criterion (a)(2) equipment

LRA Section 3.5.2.1.2, Water Control Structures, Materials, is revised as follows.

Water control structures components subject to aging management review are constructed of the following materials.

- carbon steel
- concrete
- concrete brick
- <u>fiberglass</u>
- galvanized steel
- <u>stainless steel</u>

LRA Section 3.5.2.1.4, Water Control Structures, Bulk Commodities, Materials, is revised as follows.

Bulk commodities subject to aging management review are constructed of the following materials.

- aluminum
- carbon steel
- cera blanket
- cerafiber
- concrete
- <u>copper alloy</u>
- elastomer
- fiberglass/calcium silicate
- galvanized steel
- mineral wool
- pyrocrete
- stainless steel

LRA Table 3.5.2-2, Water Control Structural Components and Commodities (IP2 and IP3), is revised to add the following line items.

3.5.2-2: Water Control Structures Structural Components and Commodities (IP2 and IP3)								
Structure and/or Component or Commodity	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
<u>Baffling/grating partition and support platform (steel portion) (IP3)</u>	<u>SNS</u>	<u>Stainless steel</u>	<u>Exposed to fluid environment</u>	<u>Loss of material</u>	<u>Structures monitoring</u>	<u>III.A6-11 (T-21)</u>	<u>3.5.1-47</u>	<u>E</u>

3.5.2-2: Water Control Structures Structural Components and Commodities (IP2 and IP3)								
Structure and/or Component or Commodity	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Baffling/grating partition and support platform (fiberglass portion) (IP3)	SNS	Fiberglass	Exposed to fluid environment	Loss of material	Structures monitoring			J

LRA Table 3.5.2-4, Summary of Bulk Commodities, Summary of Aging Management Review, is revised to add the following line items.

Table 3.5.2-4: Bulk Commodities								
Structure and/or Component or Commodity	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Anchor bolts	SNS	Stainless steel	Exposed to fluid environment	Loss of material	Structures monitoring	III.A6-11 (T-21)	3.5.1-47	E
Structural bolting	SNS	Copper alloy	Exposed to fluid environment	Loss of material	Structures monitoring	III.A6-11 (T-21)	3.5.1-47	E

LRA Section B.1.36, Structures Monitoring, Enhancements, is revised to include the following enhancement for elements 1 and 4.

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. Also, inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years.

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

- Revise applicable structures monitoring procedures to inspect normally submerged concrete portions of the intake structures at least once every 5 years. Also, inspect the baffling/grating partition and support platform of the intake structure at least once every 5 years.

The definition of a "selected set" of components inspected by the Selective Leaching Program is added to the LRA.

LRA Section B.1.33, Program Description, is revised as follows.

The Selective Leaching Program is a new program that will ensure the integrity of components made of gray cast iron, bronze, brass, and other alloys exposed to raw water, treated water, or groundwater that may lead to selective leaching. The program will include a one-time visual inspection, hardness measurement (where feasible based on form and configuration) or other industry-accepted mechanical inspection techniques of selected components that may be susceptible to selective leaching to determine whether loss of material due to selective leaching is occurring, and whether the process will affect the ability of the components to perform their intended function through the period of extended operation.

The selected set or representative sample size will be based on Chapter 4 of EPRI document 107514, Age Related Degradation Inspection Method and Demonstration, which outlines a method to determine the number of inspections required for 90% confidence that 90% of the population does not experience degradation (90/90). Each group of components with the same material-environment combination is considered a separate population.

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

The Diesel Fuel Monitoring Program is enhanced to include sampling activities when transferring fuel oil with the onsite portable fuel oil tanker.

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

- Revise applicable procedures to direct sampling of the onsite portable fuel oil tanker contents prior to transferring the contents to the storage tanks.

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

- Revise applicable procedures to direct sampling of the onsite portable fuel oil tanker contents prior to transferring the contents to the storage tanks.

LRA Section B.1.9, Diesel Fuel Monitoring, Enhancements, is revised to add the following.

2. Preventive Actions	Revise applicable procedures to direct sampling of the onsite portable fuel oil tanker contents prior to transferring the contents to the storage tanks.

The Diesel Fuel Monitoring Program is enhanced to add the security diesel fuel oil storage tank to the list of tanks sampled quarterly for particulates, water, and sediment.

LRA Section A.2.1.8, Diesel Fuel Monitoring Program, fourth paragraph, second bullet is revised as follows.

- Revise applicable procedures to include quarterly sampling and analysis of the SBO/Appendix R diesel generator fuel oil day tank, security diesel fuel oil storage tank, and security diesel fuel oil day tank. Particulates (filterable solids), water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be ≤ 10mg/l. Water and sediment acceptance criterion will be ≤ 0.05%.

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

2. Preventive Actions 4. Detection of Aging Effects 5. Monitoring and Trending	IP2: Revise applicable procedures to include quarterly sampling and analysis of the SBO/Appendix R diesel generator fuel oil day tank<u>, security diesel fuel oil storage tank,</u> and security diesel fuel oil day tank. Particulates (filterable solids), water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be $\leq$ 10mg/l. Water and sediment acceptance criterion will be $\leq$ 0.05% IP3: Revise applicable procedures to include quarterly sampling and analysis of the Appendix R fuel oil storage tank. Particulates (filterable solids), water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be $\leq$ 10mg/l. Water and sediment acceptance criterion will be $\leq$ 0.05%

The Water Chemistry Control – Closed Cooling Water Program is enhanced to monitor security generator and fire protection diesel cooling water for pH and glycol within limits specified by EPRI guidelines.

LRA Section A.2.1.39, Water Chemistry Control – Closed Cooling Water Program, third paragraph, second bullet, is revised as follows.

- Revise appropriate procedures to maintain the security generator <u>and fire protection diesel</u> cooling water ~~system~~ pH <u>and glycol</u> within limits specified by EPRI guidelines.

LRA Section A.3.1.39, Water Chemistry Control – Closed Cooling Water Program, third paragraph, first bullet, is revised as follows.

- Revise appropriate procedures to maintain security generator <u>and fire protection diesel</u> cooling water pH <u>and glycol</u> within limits specified by EPRI guidelines.

LRA Section B.1.40, Water Chemistry Control – Closed Cooling Water Program, Enhancements, is revised as follows.

2. Preventive Actions 3. Parameters Monitored or Inspected 5. Monitoring and Trending 6. Acceptance Criteria	IP2: Revise appropriate procedures to maintain water chemistry of the SBO/Appendix R diesel generator cooling system per EPRI guidelines. IP2: Revise appropriate procedures to maintain the security generator and fire protection diesel cooling water ~~system~~ pH and glycol within limits specified by EPRI guidelines. IP3: Revise appropriate procedures to maintain security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.

The Diesel Fuel Monitoring Program is enhanced to perform thickness measurements on the IP3 EDG fuel oil storage tanks.

LRA Section A.3.1.8, Diesel Fuel Monitoring Program, fourth paragraph, third bullet, is revised as follows.

- Revise applicable procedures to include thickness measurement of the bottom surface of the EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank once every ten years.

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

4. Detection of Aging Effects	IP2: Revise applicable procedures to include thickness measurement of the bottom surface of the EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel day tank, GT1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank once every ten years. IP3: Revise applicable procedures to include thickness measurement of the bottom surface of the EDG fuel oil day tanks, <u>EDG fuel oil storage tanks,</u> Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank once every ten years.

The Metal-Enclosed Bus Inspection Program is enhanced to clarify the acceptance criteria for metal enclosed bus internal inspections.

LRA Section A.2.1.19, Metal-Enclosed Bus Inspection Program, third paragraph, is revised to add the following enhancement.

- <u>Revise acceptance criteria of appropriate procedures for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct.</u>

LRA Section A.3.1.19, Metal-Enclosed Bus Inspection Program, third paragraph, is revised to add the following enhancement.

- <u>Revise acceptance criteria of appropriate procedures for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct.</u>

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

6. Acceptance Criteria	Revise the acceptance criteria for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct.

ATTACHMENT 2 TO NL-08-057

Audit TLAA and other LRA Amendment

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

INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL APPLICATION (LRA) AMENDMENT

Audit Item 3

LRA Table 4.3-1, IP2 Analyzed and Projected Number of Thermal Cycles, Abnormal Conditions, is revised as follows.

Abnormal Conditions			
Transient Condition	**Analyzed Numbers of Cycles**	**Cycles as of 5/24/2005**	**60-year Projection 9/28/2033[1]**
Reactor trip	400	239	~~292[3]~~ 301[3]
- No excessive cooldown	230	88	~~124~~ 131[3]
- Excessive cooldown	160	148	~~159~~ 160[3]
- Excessive cooldown with safety injection	10	3	~~9~~ 10[3]

LRA Table 4.3-1, footnote 3, is revised as follows.

3. Total reactor trips were projected by summing the three sub-categories of trips below this entry, not by projecting the totals. This gives a conservative result due to the round up on each of the three parts. The three sub-categories of reactor trips were projected based on the six year period from 1999 to 2005. The 336 days that the unit was shutdown in 2000-2001 were not used in the projection.

Audit Item 7

LRA Section 4.3.1, Class 1 Fatigue, Unit 2, third paragraph, is revised as follows.

The 60-year projections for IP2 show the following.

The only normal condition projecting above the analyzed number of cycles is steady state fluctuations. The projection is 1.5×10^6 while the analyzed number is 1×10^6. However, the value shown in Table 4.3-1 is not based on actual cycles. The value shown in Table 4.3-1 ~~for cycles as of 10/31/1999~~ is a calculated value based on the assumption that the transients occur at a constant rate that results in a number of transients occurring over 40 years based on this calculated value is 1.5 times the analyzed number of transients. In accordance with the Fatigue Monitoring Program, prior to the period of extended operation, corrective actions will be taken to confirm that monitoring is not required or to establish appropriate monitoring.

Audit Item 8

LRA Table 4.3-5, CUFs for the IP2 Reactor Vessel Internals, location upper support plate assembly, is revised to replace the existing CUF of 0.173 with 0.81.

Audit Items 9, 12, 141

LRA Section 4.3.1.3, Pressurizer, second paragraph, is revised as follows.

> Section 4.3.1 projected the numbers of cycles of ~~the~~ all transients used in the pressurizer fatigue determination, except steady state oscillations, would remain below the numbers analyzed by the stress report through the period of extended operation. The stress report analyzed the 1~~0~~E6 steady state oscillations only for condition N-415.1(b), where these oscillations were determined to be "Not Significant." The projection of steady state oscillations therefore does not affect the results of the stress report evaluation of N-415.1. Therefore the number of significant cycles will remain below that analyzed by the stress report. ~~Thus the TLAA for determining that detailed fatigue analyses are not required remains valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i).~~

Audit Item 10

LRA Section 4.3.1, Class 1 Fatigue, Unit 2, third paragraph, second sub-paragraph, is revised as follows.

> ~~Feedwater cycling , a replacement steam generator design transient limited to 18,300 cycles, does not appear on Table 4.3-1. The value of 18,300 is the projected value for 40 years of steam generator operation. Since the IP2 replacement steam generators will not be in service for 40 years at the end of the period of extended operation, feedwater cycling is not expected to exceed the analyzed number of cycles.~~
>
> Feedwater cycling is a transient that affects the replacement steam generators. The steam generators are analyzed for 18,300 cycles. However, the 18,300 cycles do not appear on Table 4.3-1 since these cycles have no significant impact on the RCS. Instead, Table 4.3-1 includes 2000 feedwater cycles. These are cycles that are significant enough to affect the RCS.

Audit Item 11

Refer to Item 12 below for revisions to Tables 4.1-1 and 4.1-2 related to this item.

LRA Section 4.3.1.1, Reactor Vessel, second paragraph, is revised as follows.

Design cyclic loadings and thermal conditions for the reactor pressure vessel were originally defined in the design specifications and analyzed in the original vessel stress reports. These analyses have been occasionally revised, most recently for the extended power uprate. These latest analyses are reflected in the current UFSAR tables. As described in Section 4.3.1, the projected numbers of transient cycles used for reactor vessel fatigue analyses remain within analyzed values. ~~Consequently, the TLAA (reactor vessel fatigue analyses) based on those transients will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i) for both IP2 and IP3.~~ The effects of fatigue on the reactor vessel will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3.

LRA Table 4.3-1 is revised to add footnote 4 to the "Loss of power" transient condition.

4. Loss of power transients involve the loss of the turbine generator bus followed by reactor and turbine trips. The reactor vessel fatigue analyses do not identify loss of power as unique transients.

Audit Items 12, 144

LRA tables 4.1-1 and 4.1-2 revised as follows.

Table 4.1-1
List of IP2 TLAA and Resolution

TLAA Description	Resolution Option	Section
Reactor Vessel Neutron Embrittlement Analyses		
Charpy upper-shelf energy	Analyses projected 10 CFR 54.21(c)(1)(ii)	4.2.2
Pressure/temperature limits	P-T limit curves managed 10 CFR 54.21(c)(1)(iii)	4.2.3
Low temperature overpressure protection (LTOP)	LTOP limits managed 10CFR54.21(c)(1)(iii)	4.2.4
Pressurized thermal shock	Analysis projected 10 CFR 54.21(c)(1)(ii)	4.2.5

Table 4.1-1
List of IP2 TLAA and Resolution

TLAA Description	Resolution Option	Section
Metal Fatigue Analyses		
Reactor vessel	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.1
Reactor vessel internals	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.2
Pressurizer	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.3
Pressurizer insurge/outsurge transients	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.3
Steam generator	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.4
Reactor coolant pump	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.5
Control rod drive mechanisms	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.6

Table 4.1-1
List of IP2 TLAA and Resolution

TLAA Description	Resolution Option	Section
Regenerative letdown heat exchanger	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.7
Class 1 piping and in-line components—ANSI B31.1 piping	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.8
Class 1 piping and in-line components—pressurizer surge line	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.8
Class 1 piping and in-line components—thermowells	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.8
Class 1 piping and in-line components —charging system	Analysis will be updated as part of environmental fatigue evaluation. See Section 4.3.3.	4.3.1.8
Class 1 piping and in-line components—loop 3 accumulator nozzle	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.8
Non-Class 1 piping and in-line components	Analyses remain valid 10 CFR 54.21(c)(1)(i)	4.3.2
~~Non-Class 1, non-piping components - residual heat removal heat exchanger~~	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~	~~4.3.2~~
Effects of reactor water environment on fatigue life	Aging effect managed 10 CFR 54.21(c)(1)(iii)	4.3.3

Table 4.1-1
List of IP2 TLAA and Resolution

TLAA Description	Resolution Option	Section
Environmental Qualification Analyses Of Electrical Equipment	Aging effect managed 10 CFR 54.21(c)(1)(iii)	4.4
Concrete Containment Tendon Prestress Analyses	IPEC does not have pre-stressed tendons in the containment structures.	4.5
Containment Liner Plate and Penetrations Fatigue Analyses		
Containment penetration (feedwater line #22) fatigue analysis	Analyses remain valid 10 CFR 54.21(c)(1)(i)	4.6
Other TLAA		
Leak before break	Analysis remains valid 10 CFR 54.21(c)(1)(i)	4.7.2
Steam generator flow-induced vibration (tube wear)	Analyses remain valid 10 CFR 54.21(c)(1)(i)	4.7.3

Table 4.1-2
List of IP3 TLAA and Resolution

TLAA Description	Resolution Option	Section
Reactor Vessel Neutron Embrittlement Analyses		
Charpy upper-shelf energy	Analyses projected 10 CFR 54.21(c)(1)(ii)	4.2.2

Table 4.1-2
List of IP3 TLAA and Resolution

TLAA Description	Resolution Option	Section
Pressure/temperature limits	P-T limit curves managed 10 CFR 54.21(c)(1)(iii)	4.2.3
Low temperature overpressure protection (LTOP)	LTOP limits managed 10CFR54.21(c)(1)(iii)	4.2.4
Pressurized thermal shock	Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.2.5
Metal Fatigue Analyses		
Reactor vessel	~~Analyses remain valid~~ ~~10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.1
Reactor vessel internals	~~Analyses remain valid~~ ~~10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.2
Pressurizer	~~Analyses remain valid~~ ~~10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.3
Pressurizer insurge/outsurge transients	~~Analyses remain valid~~ ~~10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.3
Steam generator	~~Analyses remain valid~~ ~~10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.4

Table 4.1-2
List of IP3 TLAA and Resolution

TLAA Description	Resolution Option	Section
Reactor coolant pump	~~Analyses remain valid~~ ~~10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.5
Control rod drive mechanisms	~~Analyses remain valid~~ ~~10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.6
Regenerative letdown heat exchangers	~~Analyses remain valid~~ ~~10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.7
Class 1 piping and in-line components—B31.1 piping	~~Analyses remain valid~~ ~~10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.8
Class 1 piping and in-line components —pressurizer surge line	~~Analyses remain valid~~ ~~10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.8
Class 1 piping and in-line components —thermowells	~~Analyses remain valid~~ ~~10 CFR 54.21(c)(1)(i)~~ Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.8
Class 1 piping and in-line components —charging system	Analysis will be updated as part of environmental fatigue evaluation. See Section 4.3.3. Aging effects managed 10 CFR 54.21(c)(1)(iii)	4.3.1.8
Non-Class 1 piping and in-line components	Analyses remain valid 10 CFR 54.21(c)(1)(i)	4.3.2

Table 4.1-2
List of IP3 TLAA and Resolution

TLAA Description	Resolution Option	Section
~~Non-Class 1, non-piping components—residual heat removal heat exchanger~~	~~Analyses remain valid 10 CFR 54.21(c)(1)(i)~~	~~4.3.2~~
Effects of reactor water environment on fatigue life	Aging effect managed 10 CFR 54.21(c)(1)(iii)	4.3.3
Environmental Qualification Analyses of Electrical Equipment	Aging effect managed 10 CFR 54.21(c)(1)(iii)	4.4
Concrete Containment Tendon Prestress Analyses	IPEC does not have pre-stressed tendons in the containment structures.	4.5
Containment Liner Plate and Penetrations Fatigue Analyses	No TLAA for these components.	4.6
Other TLAA		
Leak before break	Analysis remains valid 10 CFR 54.21(c)(1)(i)	4.7.2
Steam generator flow-induced vibration (tube wear)	Analyses projected 10 CFR 54.21(c)(1)(ii)	4.7.3

LRA Section 4.3.1.2, Reactor Vessel Internals, is revised as follows.

The IPEC reactor vessel internals were designed to meet the intent of Subsection NG of the ASME Boiler and Pressure Vessel Code, Section III. A plant-specific stress report on the reactor internals was not required. The structural integrity of the reactor internals design has been ensured by analyses performed on both generic and plant-specific bases. These analyses were used as the basis for evaluating critical reactor internal components with

CUFs provided in Tables 4.3-5 and 4.3-6. The effects of fatigue on the reactor vessel internals will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3.

LRA Section 4.3.1.3, Pressurizer, fifth paragraph and Insurge/Outsurge Transients (second paragraph), are revised as follows.

None of the design transients used in the analysis of the pressurizer will be exceeded as discussed in Section 4.3.1. ~~The pressurizer fatigue analyses will thus remain valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i).~~ The effects of fatigue on the pressurizer will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3.

Insurge/Outsurge Transients

The effects of fatigue on the pressurizer will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3. ~~As t~~The cycles on which these analyses are based will not be exceeded through the period of extended operation.~~,~~ ~~these TLAA remain valid through the period of extended operation per 10CFR54.21(c)(1)(i).~~ Nonetheless, as identified above, the surge nozzles require environmental fatigue considerations~~, they~~ and will be reanalyzed for license renewal as discussed in Section 4.3.3.

LRA Section 4.3.1.4, Steam Generators, Evaluation, is revised as follows.

Section 4.3.1 projects that none of the design transients used for steam generator fatigue analysis will exceed their analyzed numbers during the period of extended operation. These usage factor calculations are based on the design transients discussed in Section 4.3.1~~ and will remain valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i)~~. The effects of fatigue on the steam generators will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3.

LRA Section 4.3.1.5, Reactor Coolant Pump Fatigue Analysis, second paragraph, is revised as follows.

Detailed fatigue analyses of RCP casings were not required because the conditions specified in the 1965 edition of the ASME code Sections N-415.1(a) through (f), "Vessels Not Requiring Analysis for Cyclic Operation," were met. These fatigue waiver evaluations may be considered TLAA if they used the numbers of design cycles in the evaluation of items N-415.1(a) through (f). IPEC has chosen to conservatively call the evaluations TLAA. These determinations were based on the numbers of design cycles. The projections in Tables 4.3-1 and 4.3-2 show that the numbers of significant cycles in 60 years will remain below the numbers of cycles used in these determinations. The effects of fatigue on the reactor coolant pumps will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3.~~Thus the TLAAs for determining that~~

~~detailed fatigue analyses are not required remain valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i).~~

Unit 2

From stretch power uprate analyses, the CUF for the RCP main flange bolts is 0.44. ~~As t~~This CUF is based on the design transients and the design transients will not be exceeded. The effects of fatigue on the main flange bolts will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii).~~, the calculation of CUF for the main flange bolts remains valid for the period of extended operation in accordance with 10CFR54.21(1)(c)(i).~~

Unit 3

From stretch power uprate analyses, the CUF for the RCP main flange bolts is 0.32. ~~As t~~This CUF is based on the design transients, and the design transients will not be exceeded. The effects of fatigue on the main flange bolts will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii).~~, the calculation of CUF for the main flange bolts remains valid for the period of extended operation in accordance with 10CFR54.21(1)(c)(i).~~

LRA Section 4.3.1.6, Control Rod Drive Mechanisms, last paragraph, is revised as follows.

As discussed in Section 4.3.1, the numbers of analyzed design transients used in this fatigue analysis will not be exceeded in 60 years of operation. The effects of fatigue on the control rod drive mechanisms will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii).~~and thus this TLAA will remain valid through the period of extended operation in accordance with 10CFR54.21(c)(1)(i).~~

LRA Section 4.3.1.7, Class-1 Heat Exchangers, second paragraph, is revised as follows.

Westinghouse determined that the regenerative heat exchanger was the controlling heat exchanger with regards to fatigue, and therefore only that heat exchanger was analyzed. The associated report concludes that by 10/31/1999, Unit 2 had accumulated 466 of the analyzed 2000 cycles (23.3%) on the regenerative heat exchanger. Further, since the analyzed CUF was only 0.235, the CUF as of 10/31/1999 was equal to 0.235 x 23.3% = 0.05. For license renewal, the thermal cycles seen by the regenerative heat exchanger can be projected through the period of extended operation to show that only 1072 cycles (54%) are expected in 60 years, corresponding to a projected CUF of 0.235 x 54% = 0.13. The IP3 auxiliary heat exchangers have no plant-specific evaluation. However, the similarity in design and operation between the two units indicates the results would be similar. As the projected IP2 CUF is 0.13, it follows that the IP3 CUF would also be well below the limit of 1.0, such that a plant-specific analysis is not required. Thus the aging effects due to fatigue on Class 1 heat exchangers will be managed for the period of extended operation in accordance with 10CFR54.21(c)(1)(iii). ~~Thus the TLAA for the heat exchanger fatigue remains valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i).~~

LRA Section 4.3.1.8, Class 1 Piping and Components, Pressurizer Surge Line Piping, second paragraph, is revised as follows.

> The site-specific evaluations of the pressurizer surge line are considered TLAA since the evaluations use time-limited assumptions such as thermal and pressure transients, and operating cycles. The dominant cycles in the surge line analysis are the 200 heatups and cooldowns, including the stratification and striping associated with those transients. As discussed in Section 4.3.1, the number of analyzed heatups/cooldowns, as well as the other design transients presented in Tables 4.3-1 and 4.3-2, will not be exceeded in 60 years of operation. ~~Thus this TLAA remains valid through the end of the period of extended operation in accordance with 10CFR54.21(c)(1)(i).~~ The effects of fatigue on the pressurizer surge line piping will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii).

LRA Section 4.3.1.8, Class 1 Piping and Components, Thermowells, is revised as follows.

> Westinghouse identified cumulative usage factors for various thermowells associated with the IPEC pressurizers based on 200 heatups and cooldowns with a maximum CUF of 0.021. ~~Since~~ Table 4.3-1 and Table 4.3-2 project that 200 heatups and cooldowns will not be exceeded~~, this TLAA remains valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i).~~ The effects of fatigue on thermowells will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii).

LRA Section 4.3.1.8, Class 1 Piping and Components, IP2 Loop 3 Accumulator Nozzle, is revised as follows.

> The IP2 loop 3 accumulator nozzle does not have a thermal sleeve. Although this piping was built to B31.1 and no fatigue analysis of the piping was originally performed, a fatigue analysis was performed to justify continued operation without the thermal sleeve. An analysis of the nozzle determined the CUF to be 0.95. This analysis was based on the same design cycles as the reactor vessel, and those analyzed numbers of cycles will not be exceeded for 60 years of operation~~. Therefore, this TLAA for the IP2 loop 3 accumulator nozzle remains valid for the period of extended operation per 10CFR54.21(c)(1)(i).~~ The effects of fatigue on the IP2 loop 3 accumulator nozzle will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii).

LRA Section A.2.2.2.1, Class 1 Metal Fatigue, second paragraph, is revised as follows.

> The Fatigue Monitoring Program will assure that the analyzed number of transient cycles is not exceeded. The program requires corrective action if the analyzed number of transient cycles is approached. Consequently, the effects of aging related to these TLAA (fatigue analyses) based on those transients will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii). ~~for both IP2 and IP3remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).~~

LRA Section A.3.2.2.1, Class 1 Metal Fatigue, second paragraph, is revised as follows.

The Fatigue Monitoring Program will assure that the analyzed number of transient cycles is not exceeded. The program requires corrective action if the analyzed number of transient cycles is approached. Consequently, the effects of aging related to these TLAA (fatigue analyses) based on those transients will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii). ~~for both IP2 and IP3remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).~~

Audit Item 13

LRA Section 4.3.1.3, Pressurizer, Insurge/Outsurge, first paragraph, is revised as follows.

The impact of pressurizer insurge/outsurge transients was not considered in original design basis calculations for the pressurizer. The IP2 CUF of record for the pressurizer surge nozzle remains the original design stress report number of 0.264. IP3 re-evaluated the CUF of the pressurizer surge line nozzle considering insurge/outsurge during the 200 design heatups and cooldowns. The revised CUF for IP3 is 0.9612. The CUFs are reflected in Tables 4.3-7 and 4.3-8. If the IP2 surge nozzle was to be reanalyzed for insurge/outsurge it is expected the resulting increase would be similar to the increase for IP3. Since both plants had CUFs of approximately 0.26 (0.2589 and 0.264) without consideration of insurge/outsurge, then both would be expected to have CUFs of approximately 0.96 for 200 heatups with consideration of insurge/outsurge. However, no TLAA to address insurge/outsurge exists for IP2. Both the IP2 and IP3 surge nozzles will be re-evaluated for environmentally assisted fatigue prior to the period of extended operation. That re-analysis will consider not only environmental factors, but also the effects of insurge/outsurge for both units.

Audit Item 14

LRA Table 4.3-1, IP2 Analyzed and Projected Number of Thermal Cycles, Footnote 2, is revised as follows.

2. Hydro tests are no longer required or performed as a result of changes to ASME Section XI. Therefore hydro tests are projected to remain at the current value for the remainder of plant life. Section 3.0 of WCAP-16169 states the vessel is ~~currently~~ analyzed for 200 hydrotests.

LRA Table 4.3-2, IP3 Analyzed and Projected Number of Thermal Cycles, is revised as follows.

Table 4.3-2
IP3 Analyzed and Projected Number of Thermal Cycles

	Transient Condition	Analyzed Numbers of Cycles	Cycles as of 3/31/2006	60-year Projection[1] 12/12/2035
1	Plant heatup at 100°F per hr	200	~~Note 2~~ 55	~~120[2]~~ 109[2]
2	Plant cooldown at 100°F per hr	200	~~Note 2~~ 55	~~120[2]~~ 109[2]

~~2. Cycle projection based on rate of occurrence of cycles between 1975 and 1995. Projection is the number of cycles as of 12/31/1995 plus the rate per day times the number of days from 12/31/1995 to the end of the period of extended operation.~~

3. Hydro tests are no longer required or performed as a result of changes to ASME section XI. Current values are zero and projections are zero.

Audit Items 17 and 142

LRA Section 4.3.1.7, Class-1 Heat Exchangers, is revised as follows.

The original manufacturing equipment specification for the regenerative letdown heat exchangers and the excess letdown heat exchangers says these heat exchangers are to be qualified for various transients. The E-spec suggests that the manufacturer should verify in writing that all conditions of Paragraph N-415.1 of Section III are satisfied for the transient conditions; otherwise, a fatigue analysis is required. The IPEC UFSARs say the regenerative letdown heat exchangers and the excess letdown heat exchangers are qualified to 2000 temperature cycles from 100 deg F to 560 deg F associated with charging and letdown stops and starts.

Westinghouse determined that the regenerative heat exchanger was the controlling heat exchanger with regards to fatigue, and therefore only that heat exchanger was analyzed. The associated report concludes that by 10/31/1999, Unit 2 had accumulated 466 of the analyzed 2000 cycles (23.3%) on the regenerative heat exchanger. Further, since the analyzed CUF was only 0.235, the CUF as of 10/31/1999 was equal to 0.235 x 23.3% = 0.05. For license renewal, the thermal cycles seen by the regenerative heat exchanger can be projected through the period of extended operation to show that only 1072 cycles (54%) are expected in 60 years, corresponding to a projected CUF of 0.235 x 54% = 0.13. The IP3 auxiliary heat exchangers have no plant-specific evaluation, and therefore, there is no TLAA. However, the similarity in design and operation between the two units indicates the results would be similar. As the projected IP2 CUF is 0.13, it follows that the IP3 CUF would also be well below the limit of 1.0, such that a plant-specific analysis, if performed, would satisfy the code CUF limit ~~is not required~~. The Fatigue Monitoring Program will count the transients experienced by the units and require action if any analyzed number of transients is approached during the period of extended operation. Thus the aging effects due to fatigue on Class 1 heat exchangers will be managed for the period of extended operation in accordance with 10CFR54.21(c)(1)(iii). ~~Thus this TLAA remains valid through the end of the period of extended operation in accordance with 10CFR54.21(c)(1)(i).~~

IPEC design documents indicate that the auxiliary heat exchangers are not the limiting components in the CVCS system. The charging nozzles at the RCS cold leg piping are more limiting. Therefore, monitoring of the charging nozzles will assure acceptability of the auxiliary heat exchangers. Because the charging nozzle is one of the locations identified by NUREG-6260 as requiring environmental adjustments to the fatigue analysis, this nozzle will be evaluated with the other NUREG-6260 locations as discussed in Section 4.3.3.

Audit Item 112

Add LRA Section 4.3.4, References, as follows.

~~4.3.4 References~~

4.3-1 NL-04-005, Entergy to NRC, Indian Point 2, "Indian Point Nuclear Generating Unit No. 2, Stretch Power Uprate, NSS and BOP Licensing Report", January, 2004

4.3-2 NRC Letter, Patrick D. Milano to Mike Kansler, Entergy, "Indian Point Nuclear Generating Unit No. 2 – Issuance of Amendment Re: 3.26 Percent Power Uprate", October 27, 2004.

4.3.3 NL-04-069, Entergy to NRC, Indian Point 3, "Proposed Changes to Technical Specifications: Stretch Power Uprate (4.85%) and Adoption of TSTF-339", June, 2004.

4.3-4 NRC Letter, Patrick D. Milano to Mike Kansler, Entergy, "Indian Point Nuclear Generating Unit No. 33 – Issuance of Amendment Re: 4.85 Percent Stretch Power Uprate and Relocation of Cycle-specific Parameters", March 24, 2005.

4.3-5 NRC Letter, Herbert N. Berkow to Robert H. Bryan, Chairman, Westinghouse Owner's Group, "Safety Evaluation of Topical Report WCAP-15666, Extension of Reactor Coolant Pump Motor Flywheel Examination", May, 2003

Audit Item 118

LRA Section 4.3, Metal Fatigue, third paragraph, is revised as follows.

Fracture mechanics analyses of flaws discovered during in-service inspection may be TLAA for those analyses based on time-limited assumptions defined by the current operating term. When a flaw is detected during in-service inspections, ~~either~~ the component may be replaced, ~~flaw must be~~ repaired, or ~~the component that contains the flaw can be~~ evaluated for continued service in accordance with ASME Section XI. These evaluations may show that the component is acceptable to the end of the license term based on projected in-service flaw growth. Flaw growth is typically predicted based on the design thermal and mechanical loading cycles.

Audit Item 134

LRA Table 4.3-2, IP3 Analyzed and Projected Number of Thermal Cycles, is revised as follows.

Table 4.3-2
IP3 Analyzed and Projected Number of Thermal Cycles

Transient Condition		Analyzed Numbers of Cycles	Cycles as of 3/31/2006	60-year Projection[1] 12/12/2035
14	Operating basis earthquake (OBE)[5]	5	0	0
15	Design basis earthquake (DBE)[5]	1	0	0

5. The upset conditions include the effect of the specified earthquake for which the system must remain operational or must regain its operational status. The faulted conditions include the earthquake for which safe shutdown is required. For fatigue studies, Class I components were analyzed for five OBEs and one DBE in addition to other fatigue producing events. Each earthquake is considered to produce ten peak stress magnitudes.

Audit Item 135

LRA Tables 4.3-13 and 4.3-14, IP2 (IP3) Cumulative Usage Factors for NUREG/CR-6260 Limiting Locations is revised to replace footnote 1 with the following and move the footnote reference from NUREG-6260 location "Pressurizer surge line nozzle" to "Surge line piping".

1. The maximum usage factor on IPEC surge lines occurred at the pipe side of the pressurizer nozzle safe end with a maximum value of 0.60.

Audit Item 141

LRA Section 4.3.1.3, Pressurizer, fourth and fifth paragraphs, are revised as follows.

While ~~T~~the original stress report did not analyze the pressurizer shell, it did analyze the surge nozzle and spray nozzle. The resulting CUFs are not the CUFs of record as both the surge and spray nozzles were subsequently re-evaluated for the stretch power uprates.

~~The IPEC pressurizers were evaluated for the stretch power uprates and cumulative usage factors were updated.~~ The ~~U~~usage factors of record are given in Tables 4.3-7 and 4.3-8.

Audit Item 143

The LRA is revised to remove the prefix to "B31.1" from the following sections and tables.

- Section 2.1.2.4.1, Packing, Gaskets, Component Seals, and O-Rings
- Table 4.1-1, List of IP2 TLAA and Resolution
- Table 4.1-2, List of IP3 TLAA and Resolution
- Section 4.3.3, Effects of Reactor Water Environment on Fatigue Life
- Table 4.3-13, IP2 Cumulative Usage Factors for NUREG/CR-6260 Limiting Locations, footnote 2
- Table 4.3-14, IP3 Cumulative Usage Factors for NUREG/CR-6260 Limiting Locations, footnote 2

LRA Section 4.3.1.8, Class 1 Piping and Components, is revised as follows.

~~ANSI~~ B31.1 Piping

The IPEC Class 1 boundary corresponds to all reactor coolant system (RCS) pressure boundary components within the ASME Section XI, IWB inspection boundary.

The B31.1 power piping code originated in 1955 as ASA B31.1. In 1967 it became USAS B31.1. It later became ANSI B31.1 and is currently ASME B31.1. The code of record for most of IP2 and some of IP3 is ASA B31.1 (1955) while the code of record for some of IP2 and most of IP3 is USAS B31.1 (1967). Use of the designation B31.1 in the application is meant to differentiate piping designed to B31.1 from piping designed to ASME Section III standards.

~~USAS~~ B31.1 was used in the design of the primary coolant piping. A thermal expansion flexibility stress analysis was performed on the main primary coolant piping in accordance with the criteria set forth in ~~USAS~~ B31.1 to ensure that the stress range is within the prescribed limits. As per the requirements of ~~USAS~~ B31.1, no fatigue analysis is required and no fatigue analysis of the reactor coolant loop piping is performed. Rather stress range reduction factors are used to account for anticipated transients (normally, a stress range reduction factor of 1.0 is acceptable in the stress analyses for up to 7000 cycles).

Audit Item 144

LRA Section 4.3.2 is revised as follows.

4.3.2 ~~Non-Class 1 Piping and Component Fatigue~~

Piping and in-line components: The design of ASME III Code Class 2 and 3 piping 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. Therefore, the pipe stress calculations are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Non-piping components: Review of potential TLAAs for IPEC non-Class 1 components identified no ~~fatigue~~ TLAA ~~related to non-Class 1 components except the residual heat removal (RHR) heat exchanger~~.

~~Residual Heat Removal Heat Exchanger~~

~~The original manufacturing equipment specification states the RHR heat exchanger is to be qualified for 200 cycles that would occur during plant shutdowns. The IP2 UFSAR, Table 6.2-8 and the IP3 UFSAR, Table 6.2-6 state the RHR heat exchangers are qualified to 200 cycles from 85 °F to 350 °F.~~

~~No fatigue analyses for these heat exchangers have been identified. It is believed that the manufacturers showed the requirements of Paragraph N-415.1 of ASME Section III were met; but no written statement from the manufacturer has been found. Nonetheless, IPEC is conservatively considering that determination a TLAA. This TLAA is considered based on the specified 200 design cycles, corresponding to the 200 design heatups/cooldowns for the reactor coolant system. The system will not exceed 200 heatups and cooldowns in 60 years as projected in Tables 4.3-1 and 4.3-2. Thus this TLAA remains valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i).~~

LRA Section A.2.2.2.2, Non-Class 1 Metal Fatigue, second paragraph is revised as follows.

~~The only non-Class1, non-piping component identified with a fatigue time-limited aging analysis was the residual heat removal heat exchanger. That heat exchanger is projected to incur less than the analyzed number of cycles and therefore the analysis will remain valid for the period of extended operation.~~

LRA Section A.3.2.2.2, Non-Class 1 Metal Fatigue, second paragraph is revised as follows.

~~The only non-Class1, non-piping component identified with a fatigue time-limited aging analysis was the residual heat removal heat exchanger. That heat exchanger is projected to incur less than the analyzed number of cycles and therefore the analysis will remain valid for the period of extended operation.~~

Audit Item 147

LRA Section 4.3.3, Effects of Reactor Water Environment on Fatigue Life, third paragraph, is revised as follows.

NUREG/CR-6260 identified locations of interest for consideration of ~~applied the fatigue design curves that incorporated~~ environmental effects in several plant designs~~to several plants and identified locations of interest for consideration of environmental effects~~. Section 5.5 of NUREG/CR-6260 identified the following component locations to be evaluated for the ~~most sensitive to~~ environmental effects on fatigue for IPEC vintage Westinghouse plants. These locations and the subsequent calculations are directly relevant to IPEC.

Audit Item 164

LRA Section B.1.12, Fatigue Monitoring, Enhancements, is revised as follows.

Attributes Affected	Enhancements
3. Parameters Monitored or Inspected	IP2: Perform an evaluation to confirm that monitoring steady state cycles and feedwater cycles is not required or revise appropriate procedures to monitor steady state cycles. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. IP3: Revise appropriate procedures to

Attributes Affected	Enhancements
	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.

LRA Section A.2.1.11, Fatigue Monitoring Program, second paragraph, first bullet, is revised as follows.

- Perform an evaluation to confirm that monitoring steady state cycles <u>and feedwater cycles</u> is not required or revise appropriate procedures to monitor steady state cycles. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures.

<u>Audit Item 562</u>

Note: The LRA tables and sections described below were revised by letter NL-07-153 to the NRC dated December 18, 2007.

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

Sight glass	Pressure boundary	Carbon steel	Treated water (int)	Cracking – fatigue	~~One-time inspection~~ <u>Periodic surveillance and preventive maintenance</u>	VIII.D1-7 (S-11)	3.4.1-1	E

LRA Table 3.3.2-19-2-IP3, Auxiliary Steam and Condensate Return System, is revised as follows.

Sight glass	Pressure boundary	Carbon steel	Treated water (int)	Cracking – fatigue	~~One-time inspection~~ <u>Periodic surveillance and preventive maintenance</u>	VIII.B1-10 (S-08)	3.4.1-1	E

LRA Table 3.3.2-19-14-IP3, Condensate Transfer System, is revised as follows.

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

LRA Table 3.3.2-19-27-IP3, Heater Drains / Moisture Separator Drains / Vents, is revised as follows.

Sight glass	Pressure boundary	Carbon steel	Steam (int)	Cracking – fatigue	~~One-time inspection~~ Periodic surveillance and preventive maintenance	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, the evaluation of fatigue is a TLAA. For some components, where no fatigue analyses exist, the ~~One-Time Inspection~~ Periodic Surveillance and Preventive Maintenance Program will manage ~~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~~ Periodic Surveillance and Preventive Maintenance Program will manage ~~confirm the absence of significant~~ cracking due to fatigue using enhanced visual or other NDE techniques.

LRA Section A.2.1.28, Periodic Surveillance and Preventive Maintenance Program, second paragraph, add the following bullet item.

- feedwater system sight glass housings

LRA Section A.3.1.28, Periodic Surveillance and Preventive Maintenance Program, second paragraph, add the following bullet item.

- auxiliary steam and condensate return system sight glass housings
- condensate transfer system sight glass housings
- *heater drain/moisture separator drains/vents systems sight glass housings*

LRA Section B.1.29, Nonsafety-related systems affecting IP2 safety-related systems, add the following activity.

Use visual or other NDE techniques to inspect a representative sample of feedwater system sight glass housings to manage cracking due to fatigue.

LRA Section B.1.29, Periodic Surveillance and Preventive Maintenance, Nonsafety-related systems affecting IP3 safety-related systems, add the following activities.

Use visual or other NDE techniques to inspect a representative sample of auxiliary steam and condensate return system sight glass housings to manage cracking due to fatigue.

Use visual or other NDE techniques to inspect a representative sample of condensate transfer system sight glass housings to manage cracking due to fatigue.

Use visual or other NDE techniques to inspect a representative sample of heater drain/moisture separator drains/vents systems sight glass housings to manage cracking due to fatigue.

Items 63 and 563

Item 63 is being revised to reflect discussion with the NRC Staff associated with draft LR-ISG-2007-02. LRA B.1.22 addresses the plant specific AMP for non-EQ bolted cable connections. Based on discussion with the NRC Staff, the AMP discussion for using visual inspection is being clarified to further explain the types of connections and personnel safety issues of opening energized equipment.

An example of where visual inspection is acceptable is motor connections where the motor lead is connected to the field cable in a local junction box. Because of personnel safety practices the junction box cover would not be removed when the cable is energized, so thermography could only be performed with the junction box cover in place, which may not provide accurate results. 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. For both of these examples, contact resistance measurements would require the destructive examination of the connection. The Entergy policies for personnel safety for energized components at a potential greater than 600V, are to observe a restricted approach boundary, which would preclude the removal of a bolted cover from energized components at a potential of greater than 600V. The number of bolted connections that are greater than 600V are limited to large motor, transformer, or generator connections (less than 30 connections, which is 3 connections per phase for 10 motors) for both units, and 5 remote MCC for both units.

LRA Section B.1.22 was previously revised with Amendment 1, Entergy Letter NL-07-153 dated 12/18/2007, and is not being changed by this clarification.

**INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION (LRA)
REQUESTS FOR ADDITIONAL INFORMATION (RAIs)
CLARIFICATION**

Structures

RAI 2.4.3-1

Section 2.4.3 of the LRA states that the fuel storage buildings have the following intended functions for 10 CFR 54.4(a)(1) and (a)(2): "Maintain integrity of non-safety related components such that safety functions are not affected by maintaining pool water inventory (Units 2 and 3)." LRA Section 2.1.2.2, "Screening of Structures," states that the screening of structural components and commodities was based primarily on whether they perform an intended function.

LRA Table 3.5.2-3, "Turbine Building, Auxiliary Building, and Other Structures Structural Components and Commodities (IP2 and IP3)," identifies structural components subject to aging management based on materials of construction and intended functions for components of structures including the fuel storage buildings. The intended functions listed in Table 3.5.2-3 (e.g., pressure boundary, missile barrier, and shelter or protection) agree with the intended functions listed in LRA Table 2.0-1, "Intended Functions: Abbreviations and Definitions." However, the intended functions for the fuel storage building listed in LRA Section 2.4.3 does not agree with the listed intended functions in LRA Tables 2.0-1 and 3.5.2-3.

Pursuant to 10 CFR 54.21, the LRA must identify and list those structures and components subject to an AMR. Clarify the LRA Section 2.4.3 description of the intended function(s) of the fuel storage building components using the list of intended functions from Table 2.0-1. To satisfy the requirements of 10 CFR 54.21, the clarification must be adequate to reasonably identify the fuel storage building structural components subject to aging management by the component/commodity, material of construction, and intended functions listed in LRA Table 3.5.2-3.

Response for RAI 2.4.3-1

The intended functions listed in Tables 2.0-1 and 3.5.2-3 are component intended functions, which are determined during the screening process. The intended functions in Section 2.4.3, in contrast, are the intended functions of the structure in its entirety and are determined during the scoping process. The scoping process determines whether or not the structure has an intended function (such as providing containment or isolation to mitigate post-accident offsite doses or providing support or protection to safety-related equipment), whereas the screening process identifies those components that support the structure intended function(s) via specific component intended functions (such as providing shelter and protection (EN) or providing support for safety-related equipment (SSR)). The structure and system level functions that are assessed against the scoping criteria of 10 CFR 54.4 are not intended to match the component level functions defined in LRA Table 2.0-1. While similarities exist between the terminology used for component intended functions versus structure intended functions, a direct correlation between the structure intended functions in Section 2.4 and the component intended functions in the tables in Section 3.5 does not exist.

Consistent with the function stated in Section 2.4.3, components of the fuel storage building perform a component-level license renewal intended function if they are required to maintain pool water inventory.

Clarification for RAI 2.4.3-1

In a telephone conversation on March 7, 2008, the NRC staff questioned whether the intended function of maintaining pool water inventory was the only intended function applicable to items included in the structural aging management review for the fuel storage buildings. In response to the request for clarification, the last paragraph of the response to RAI 2.4.3-1 provided in letter NL-08-005 dated January 4, 2008 is replaced with the following.

In addition to the function stated in Section 2.4.3, the fuel storage buildings perform the license renewal intended function of provide support and protection for safety-related equipment and nonsafety-related equipment within the scope of license renewal. Using Table 3.5.2-3, component level intended functions supporting each structure level intended function are indicated as follows.

1) *Maintain integrity of non-safety related components such that safety functions are not affected by maintaining pool water inventory (Units 2 and 3).*

Structure and/or Component or Commodity	Intended Function
Spent fuel pool liner plate and gate (IP2)	EN, SSR
Spent fuel pool liner plate and gate (IP3)	EN, SSR
Exterior walls	EN, FB, MB, PB, SNS, SSR
Exterior walls – below grade	EN, MB, PB, SNS, SSR
Floor slabs, interior walls, and ceilings	EN, FB, MB, PB, SNS, SSR

2) *Provide support and protection for safety-related equipment and nonsafety-related equipment within the scope of license renewal.*

Structure and/or Component or Commodity	Intended Function
Crane rails and girders	SNS
Metal siding	EN, FB
New fuel storage racks	EN, SSR
Roof decking	FB
Spent fuel pit bridge crane, rails and girders	SNS
Spent fuel pool storage racks	SSR
Structural steel: beams, columns, plates	MB, SNS, SSR
Exterior walls	EN, FB, MB, PB, SNS, SSR

Exterior walls – below grade	EN, MB, PB, SNS, SSR
Floor slabs, interior walls, and ceilings	EN, FB, MB, PB, SNS, SSR
Masonry walls	EN, FB, SNS, SSR
Roof slab	EN, FB, MB, PB, SNS, SSR

2.3.4.2 Main Feedwater System

RAI 2.3A.4.2-1

License renewal drawing LRA-9321-2019-0 identifies that valves FCV-417-L, FCV-417, FCV-427-L, FCV-427, FCV-437-L, FCV-437, FCV-447-L, FCV-447, BF2-21, and BF2-22, for the Unit 2 main feedwater system, are within the system evaluation boundary.

Although the aforementioned valves are passive and long-lived, they are not highlighted indicating that they are not subject to aging management in accordance with 10 CFR 54.21(a). Explain the valves' exclusion from aging management.

Clarification for RAI 2.3A.4.2-1

In a telephone conversation on March 7, 2008, the NRC staff questioned the statement that the subject valves have no passive intended function for 54.4(a)(1) or (a)(3) since their failure would accomplish the safety function of preventing feedwater flow to the steam generators. To clarify, the response to RAI 2.3A.4.2-1 provided in letter NL-08-005 dated January 4, 2008 is replaced with the following.

The LRA drawings indicate components that are included in the scope of license renewal for 10 CFR 54.4(a)(1) or (a)(3) and subject to aging management review. The subject FW system valves, which are located upstream of the containment isolation check valves in nonsafety-related piping, are classified as safety-related because of their function to provide feedwater isolation. Though not highlighted, these valves and the remainder of the FW system components on LRA drawing LRA-9321-2019-0 are in scope and subject to aging management review based on performing the intended function defined by 10 CFR 54.4(a)(2) with the component types evaluated in Table 3.3.2-19-12-IP2.

RAI 2.3B.4.2-1

License renewal drawing LRA-9321-20193-0 identifies that valves FCV-417-L, FCV-417, FCV-427-L, FCV-427, FCV-437-L, FCV-437, FCV-447-L, FCV-447, BF2-31, and BF2-32, for the Unit 3 main feedwater system are within the system evaluation boundary.

Although the aforementioned valves are passive and long-lived, they are not highlighted indicating that they are not subject to aging management in accordance with 10 CFR 54.21(a). Explain the valves' exclusion from aging management.

Clarification for RAI 2.3B.4.2-1

In a telephone conversation on March 7, 2008, the NRC staff questioned the statement that the subject valves have no passive intended function for 54.4(a)(1) or (a)(3) since their failure would accomplish the safety function of preventing feedwater flow to the steam generators. To clarify, the response to RAI 2.3A.4.2-1 provided in letter NL-08-005 dated January 4, 2008 is replaced with the following.

The LRA drawings indicate components that are included in the scope of license renewal for 10 CFR 54.4(a)(1) or (a)(3) and subject to aging management review. The subject MFW system valves, which are located upstream of the containment isolation check valves in nonsafety-related piping, are classified as safety-related because of their function to provide feedwater isolation. Though not highlighted, these valves and the remainder of the FW system components on LRA drawing LRA-9321-20193-0 are in scope and subject to aging management review based on performing the intended function defined by 10 CFR 54.4(a)(2) with the component types evaluated in Table 3.3.2-19-34-IP3.

RAI 2.5-1 (Rev. 1)

Based on discussion with the NRC Staff on 12/4/07 and industry discussion with the NRC Staff on 12/12/2007 and 1/30/2008, the response to this RAI provided in Entergy Letter NL-07-138, Dated 11/16/2007 is being revised. The only section that requires revision is LRA Figure 2.5-2 and associated discussion.

Clarification for RAI 2.5-1 (Rev. 1)

As shown in the revised LRA Figure 2.5-2, the 6.9 kV buses receive offsite power from either the 138 kV / 6.9 kV station auxiliary transformer or the 13.8 kV / 6.9 kV GT autotransformer. The station auxiliary transformer is connected to the 138 kV Buchanan substation, the primary offsite power source, via switchyard bus, overhead transmission conductors, and underground transmission conductors through ~~motor-operated disconnect F3A~~ switchyard breakers F2 and BT 3-4, which ~~is~~ are located at the Buchanan substation. The GT autotransformer is connected to the 13.8 kV Buchanan substation, the secondary offsite power source, via underground medium voltage cable through breaker F2-3, which is located at the Buchanan substation.

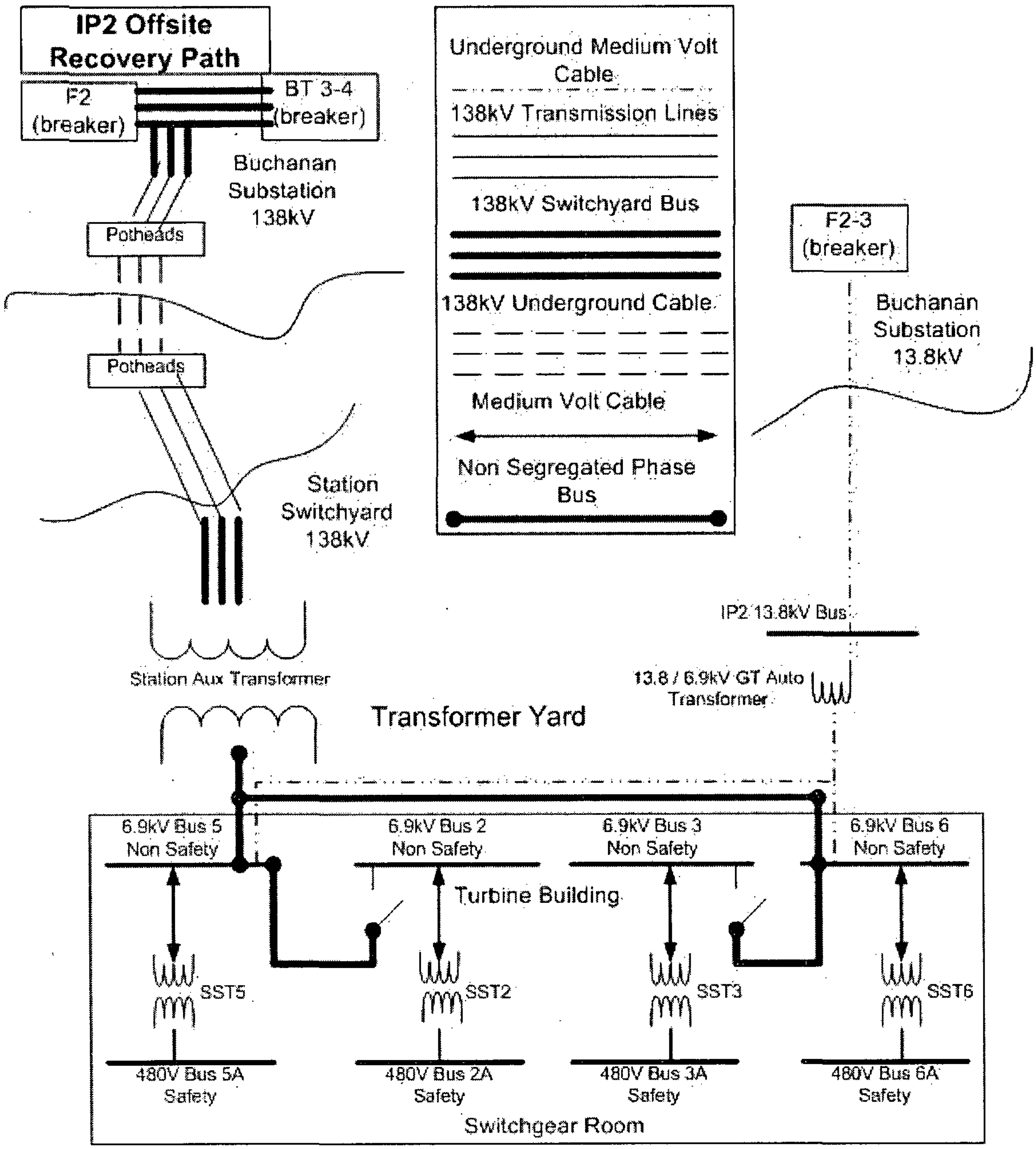

Figure 2.5-2
IP2 Offsite Power Scoping Diagram

ATTACHMENT 3 TO NL-08-057

IPEC LRA List of Regulatory Commitments, Revision 4

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

List of Regulatory Commitments

Revision 4

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 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. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201, 241, 270
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173

4	Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years. Enhance the Diesel Fuel Monitoring Program to include quarterly sampling and analysis of the IP2 SBO/Appendix R diesel generator fuel oil day tank, IP2 security diesel fuel oil storage tank, IP2 security diesel fuel oil day tank, and IP3 Appendix R fuel oil storage tank. Particulates, water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be less than or equal to 10mg/l. Water and sediment acceptance criterion will be less than or equal to 0.05%. Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom of the following tanks once every ten years. IP2: EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank; IP3: EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to change the analysis for water and particulates to a quarterly frequency for the following tanks. IP2: GT-1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank; IP3: Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program. Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected. Revise applicable procedures to direct sampling of the onsite portable fuel oil <u>contents prior to transferring the contents to the storage tanks</u>. Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.8 A.3.1.8 B.1.9 Audit items 128, 129, 132, 491, 492, 510

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
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

8	Enhance the Fire Water Program to include inspection of IP2 and IP3 hose reels for evidence of corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation. Enhance the Fire Water Program to replace all or test a sample of IP2 and IP3 sprinkler heads required for 10 CFR 50.48 using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Enhance the Fire Water Program to perform wall thickness evaluations of IP2 and IP3 fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. Enhance the Fire Water Program to inspect the internal surface of foam based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-014	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106

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

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
11	Enhance the ISI Program for IP2 and IP3 to provide periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump support systems.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.17 A.3.1.17 B.1.18 Audit item 59

12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.18 A.3.1.18 B.1.19
13	Enhance the Metal-Enclosed Bus Inspection Program to add IP2 480V bus associated with substation A to the scope of bus inspected. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material. Enhance the Metal-Enclosed Bus Inspection Program to add acceptance criteria for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to inspect bolted connections at least once every five years if performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation. The plant will process a change to applicable site procedure to remove the reference to "re-torquing" connections for phase bus maintenance and bolted connection maintenance.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.19 A.3.1.19 B.1.20 Audit Items 124, 133, 519
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.21 A.3.1.21 B.1.22

15	Implement the Non-EQ Inaccessible Medium-Voltage Cable Program for IP2 and IP3 as described in LRA Section B.1.23. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.22 A.3.1.22 B.1.23 Audit item 173
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.23 A.3.1.23 B.1.24 Audit item 173
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.24 A.3.1.24 B.1.25 Audit item 173
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
22	Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 revising the specimen capsule withdrawal schedules to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation. Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.31 A.3.1.31 B.1.32
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.32 A.3.1.32 B.1.33 Audit item 173
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.34 A.3.1.34 B.1.35

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

	• new fuel storage racks • sumps, sump screens, strainers and flow barriers Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to 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. Inspect the baffling/grating partition and support platform of the IP3 intake structure 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 and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-08-057	A.2.1.39 A.3.1.39 B.1.40 Audit item 509
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	IP2: September 28, 2013	NL-07-039	A.2.1.40 B.1.41
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	IP2: September 28, 2011 IP3: December 12, 2013	NL-07-039	A.2.1.41 A.3.1.41
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.2.1.2 A.3.2.1.2 4.2.3
32	As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS (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

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

ATTACHMENT 4 TO NL-08-057

TLAA Audit Database Report

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

Item	Request	Response
3	TLAA 4.3-1 In LRA Table 4.3 1 the applicant states that the projected 60 year reactor trips were based on an operating history from 1999 to 2005, while the other transients were based on the initial plant startup. (a) The LRA states that because plant operating practices have changed and some of the transients occur more or less often as an explanation for using the six year operating history (1999 - 2005). Please explain what plant operating practices have been changed and why these changes were not considered in the other transients' projection. (b) From February 2000 to January 2001, IP2 was shutdown because of a steam generator tube rupture (SGTR) event and subsequent steam generator replacement activities. Considering this period of shutdown, please explain the impact it has on 60-year projection for reactor trips. Also, provide reasons why it does not lessen the 60-year projection cycle number for reactor trips. (c) Page 4.3 2 of the LRA describes linear extrapolation of transients cycles. As the plant aged, the aging effects were not considered in the linear extrapolation method; please justify the validity of using linear extrapolation. (d) (Previously question #138) The extrapolation of reactor trips with excessive cooldown in Table 4.3-1 projects only 159 events after 60 years even though there are 148 events to date. Please explain this projection in detail.	(a) This statement was not intended to identify any specific operating practice; however the reduction in rate of plant trips in recent operating history versus the early years of operation is common in the nuclear industry due to lessons learned leading to better operating practices. There were substantially more reactor trips in the early years of operation at IPEC and this change in rate alone supports this statement. Recent plant data provides realistic projections of number of reactor trips expected during the period of extended operation while use of operating data for the life of the plant provides unrealistically conservative (high) projections. Based on the response to audit questions TLAA 4.3-9 and TLAA 4.3-10, the effects of fatigue due to these transients will be managed by the Fatigue Monitoring Program. The Fatigue Monitoring Program will count the actual transients experienced by the units and require appropriate action if any of the analyzed numbers of transients are approached. Consequently, these projections are only used to show that the analyzed numbers of transients are not going to be exceeded in the near future and not to justify that the existing fatigue analysis remain valid through the period of extended operation. For other transients, the change in rate of occurrence is not as significant as it is for reactor trips. Cycle projections for other transients were thus based on data for the life of the plant rather than data just from recent years. (b) If this extended shutdown period was eliminated from the timeframe used for determining the rate, the timeframe would be reduced from the 2032 days to approximately 1696 days. The projected number of trips would increase by 9 to 301 trips which is still well below the 400 analyzed cycles. Additionally, this is only a projection and the actual number of accumulated cycles will be monitored against the number of allowable cycles. Should the number of allowable cycles be approached, appropriate corrective actions including repairs and/or modifications would be implemented consistent with the requirements of the ASME Code. LRA Table 4.3-1 will be modified to reflect this revised projection of reactor trips as follows. In LRA Table 4.3-1, the values for 60-year projections will change from 292 to 301 for "Reactor trip", from 124 to 131 for "No excessive cooldown", from 159 to 160 for "Excessive cooldown", and from 9 to 10 for "Excessive cooldown with safety injection". Footnote 3 to the table will be revised to indicate that the 336 days during which the unit was shut down in 2000-2001 were not used in the projection. Clarification to be incorporated into the LRA. (c) A linear extrapolation is appropriate. Operating data shows that the rate of occurrence of transients is decreasing. Continued reduction of transient rate is economically desirable and thus will continue to be pursued. As operating experience is accrued and lessons learned are implemented, the reduction in the rate of transient occurrence is expected to continue. Many transients are projected using a linear rate that is much higher than actually experienced in recent years. The reactor trips used the more recent timeframe to determine the projection rate, but the results are still realistic. The projection of cycles is not relied on to assure code compliance. As described in LRA section B.1.12, the Fatigue Monitoring 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 without appropriate corrective action. (d) The reactor trips with excessive cooldown were projected based on data from 1999 to 2005. There were only 2 transients during this time. There were 2032 days in this timespan, but 336 days have been removed as discussed in part (b) above. The resulting rate is 0.00118 cycles per day, which projects to 160 (160.21) cycles in 60 years. LRA Table 4.3-1 will be amended as discussed in part (b) above.
4	TLAA 4.3-2 a) FSAR Tables indicate the same design transients for both IP2 and IP3. However, LRA provides a more extensive list of transients for IP2 (Table 4.3-1) than IP3 (Table 4.3-2). Explain the	The IP2 and IP3 Class 1 systems were designed for similar cyclic duty during original design and construction. Both units track these design cycles, which are included in the FSAR, to ensure that the original design requirements are not exceeded during plant operation. In addition to the original design cycles, IP2 has added a number of additional duty cycles to its fatigue monitoring program to address enhancements developed during the design of newer vintage plants but

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	basis for the differences. *The initial response for question 4.3-2 has no* references. What supports this response?	which were not included as part of the original plant design basis. IP3 is reviewing its fatigue monitoring program to determine if additional transients should be added *to its monitoring program to improve its effectiveness.* This *enhancement* is identified in Commitment 6. This response is supported by IP2 procedure 2-PT-2Y015, IP3 procedure 3PT-M051, and WCAP-12191, "Transient and Fatigue Cycle Monitoring Program, Transient History Evaluation Report for Indian Point Unit 2" which provide inputs to the Fatigue Monitoring Program. A printed copy of Section 3 of WCAP-12191 was provided on 10/23 for onsite review.
5	TLAA 4.3-3 LRA Table 4.3 1 lists some IP2 analyzed numbers of cycles for some transient conditions that do not agree with their design cycle numbers listed in IP2 FSAR Table 4.1 8. For example: Transient Condition FSAR (of Cy) LRA (of Cy) *Step load decrease of 50-percent of full power* 200 150 Hydrostatic test at 2485 psig and 400°F 5 50 (a) Please explain the discrepancies and discuss the impact on the cumulative usage factors (CUFs) for various components. (b) Indicate which number is used in the design calculation for the hydrostatic test at 2485 psig and 400 F.	(a) During past operation, IP2 has experienced leakage through the pressurizer Code safety valves. After review of industry operating experience and discussions with Westinghouse, it was concluded that lowering the RCS pressure by approximately 250 psi, would allow the safety valves to properly seat therefore eliminating the leakage. However, since the RCS had not been explicitly analyzed for this transient, the list of analyzed transients was reviewed to determine if any already analyzed transient bounded this RCS depressurization. This review indicated that a 50% step load decrease resulted in RCS pressure and temperature *changes similar to an RCS depressurization to correct safety valve leakage.* Based on this, 50 cycles were subtracted from the allowable number of step load decreases and a new limit of 50 cycles was created for RCS depressurizations for the purpose of reseating safety valves. (b) During the early phase of plant operation, IP2 routinely performed a primary side pressure test to determine steam generator primary to secondary side leakage. These pressure tests consisted of pressurizing the primary side to 2250 psi while maintaining the secondary side at essentially 0 psi. A total of 41 of these tests were performed during early plant life (i.e. prior to steam generator replacement) but this practice has since been discontinued. This test had essentially no impact on the RCS other than the steam generators. Although this test was not an RCS hydrostatic test (i.e. the RCS pressure was 2250 not 2485), these tests were conservatively added to the 2 primary side hydros because the steam generators secondary side was essentially depressurized. Since this transient only impacts the fatigue life of the steam generators, Westinghouse reviewed the steam generator stress reports and concluded that the steam generators had been designed for 50 of these cycles. In addition, since the steam generators have since been replaced and these leak tests are no longer performed, the impact of these tests on the current RCS fatigue usage has been eliminated. However, the 43 cycles remains in the monitoring program for historical purposes.
6	TLAA 4.3-4 In LRA Tables 4.3 1 and 4.3 2, a number of transient conditions for both IP2 and IP3 have 0 as the value for the 60 year projection. Please explain the conservatism behind projecting no transient conditions. Are these projected values used in any component's fatigue evaluation?	These transients have never occurred and are not expected to occur. As such, zero is the projected or expected number of transients. The projected numbers are not used in any stress calculations. The column "Analyzed Number of Cycles" provides the number of cycles used in the stress analyses.
7	TLAA 4.3-5 In LRA Table 4.3-1, the applicant lists the steady *state fluctuation cycles (781,209), as of* 5/24/2005. This date contradicts to the statement made in LRA page 4.3-2, where the applicant states that this cycle number is calculated as of 10/31/1999. (a) Please explain the discrepancy. (b) LRA indicates that steady state fluctuations are not monitored. Do steady state fluctuations contribute to the design fatigue usage factors for any component? (c) (Previously Question 121) Address whether steady state oscillations are significant to existing fatigue analyses.	(a) The statement on Page 4.3-2 includes an administrative error in referring to cycles as of 10/31/1999. The LRA will be amended to read as follows. *The 60-year projections for IP2 show the following.* The only normal condition projecting above the analyzed number of cycles is steady state fluctuations. The projection is 1.5E6 while the analyzed number is 1E6. However, the value shown in Table 4.3-1 is not based on actual cycles. The value shown in Table 4.3-1 is a calculated value based on the assumption that the transients occur at a constant rate that results in the analyzed number of transients occurring over 40 years of operation. Hence, the projection to 60 years based on this calculated value is 1.5 times the analyzed number of transients. In accordance with the Fatigue Monitoring Program, prior to the period of extended operation, actions will be taken to confirm that monitoring is not required (based on the insignificance to fatigue of these cycles as discussed below) or to establish appropriate monitoring. (b) Steady state oscillations are not a significant contributor to the fatigue of any component. See the response to item c) below. c) ASME Section III, Article 415.1(d) states "A temperature fluctuation shall be considered to be significant if its total algebraic range exceeds the quantity S/(2Me

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		Cte) where S is the value of Sa obtained from the applicable design curve for 1E6 cycles." From Figure N-415(A) of ASME Section III, Sa for 1E6 cycles (carbon steel) is 13000 psi. From Table N-426, the coefficient of thermal expansion, Cte, for carbon steel at 500°F is 7.94 E-6 in/in/°F. From Figure N-427 of ASME Section III the modulus of elasticity, Me, for carbon steel of less than 0.3% carbon at 500°F is 26.4E6 psi/in/in. This results in a significant temperature change of 13000/(2 x 7.94E-6 x 26.4E6) for a value of 31°F. As the steady state oscillations have an algebraic range of ±3°F maximum, they are not significant as defined by the ASME code. A reevaluation of the number of steady state cycles is included in Commitment 6. Clarification to be incorporated into the LRA.
8	TLAA 4.3-6 (a) LRA Section 4.3.1.2 addresses the reactor vessel internals. Indicate whether the CUFs listed in Tables 4.3-5 and 4.3-6 are based only on design thermal transients used in the reactor vessel analysis. (b) Explain why the CUF (0.173) for the IP2 upper support plate is so different from the IP3 (0.81) value.	(a) The internals component fatigue calculations use a subset of the design transients for the reactor vessel. (Not all vessel transients affect the internals. The internals see no delta-temperature or delta-pressure during heatup/cooldown as they are surrounded by reactor coolant and not exposed to containment atmosphere.) The design transients for the reactor vessel that are significant for a specific internals component are included in the individual component calculation. The CUFs are then determined based on the component-specific loadings during these transients. No other transients are included in the internals fatigue analyses. For a specific example, IP2 internals calculation CN-RCDA-03-51 evaluated 5% unit unloading, 10% step load, step load reduction from 100% to 50%, loss of flow in one loop, loss of load, reactor trip, and loss of secondary pressure. For additional information, the summaries of the power uprate evaluations for the reactor vessel internals are available in section 5.2.5 of WCAP-16156 for IP2 and WCAP-16211 for IP3. (b) The IP3 analysis was a later analysis performed for the IP3 power uprate that used a different cross section of the upper support plate than for the older IP2 analysis. The IP3 analysis resulted in a higher CUF of 0.81. The result of the IP3 analysis is also applicable to IP2. The LRA will be revised to change the CUF value for the IP2 upper support plate in Table 4.3-5 to 0.81. Information to be incorporated into the LRA.
9	In LRA 4.3.1.3 (Pressurizer), the applicant states that the impact of steady state fluctuations on pressurizer fatigue determination is "not significant." (a) Please describe any engineering analysis that was performed to make the determination of "not significant." (b) The second paragraph on LRA 4.3.1.3 states: "The stress report analyzed the 106 steady state oscillations only for condition N 415.1(b)." Please confirm if the analysis is based on 106 steady state oscillations, and not 10E6 steady state oscillations. (c) What supports the statement that the steady state oscillations are not significant to fatigue. Quote the code year used to justify this response.	(a) Section 6 of WNET-108, "44 Series Pressurizer Stress Report," states that steady state oscillations are not significant in meeting condition (b) of code paragraph N415-1 for the pressurizer shell. All six conditions were met, and no fatigue analysis (calculation of CUFs) of the pressurizer shell was performed. (b) LRA Section 4.3.1.3 contains a typographical error. It should have stated 10 to the sixth power or 1 E6 oscillations rather than 106 oscillations. WNET-108 clearly uses 1 E6 steady state oscillations. Clarification to be incorporated into the LRA. (c) See Section (c) of Question 7 for a discussion of the significance of these oscillations. WNET-108 utilizes the code of record for IP2/IP3 – ASME Section III, 1965 through the Summer of 1966 addenda.
10	TLAA 4.3-8 The first sentence of LRA page 4.3-3 states: "Feedwater cycling, a replacement steam generator design transient limited to 18,300 cycles, does not appear on Table 4.3-1. The value of 18,300 is the projected value for 40 years of steam generator operation." Feedwater cycling, however, is listed as a design	The original design bases of the IP2 RCS did not include any feedwater cycles even though the original steam generators had been designed for 25,000 feedwater cycles. This was based on the assumption that feedwater cycling had no significant impact on the RCS beyond the steam generators. However, during the design of newer vintage plants, Westinghouse added 2,000 feedwater cycles to the RCS specification. The rationale for the difference between the steam generator and the RCS cycles was that a majority of the 25,000 steam generator cycles consisted of relatively low amounts of cooler water which had little impact on the bulk secondary side water temperature and therefore no measurable impact on the RCS components. During subsequent designs, Westinghouse

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	transient in Table 4.3-1 with 2,000 analyzed cycles. Please clarify which number is the correct design basis.	decreased the number of steam generator feedwater cycles from 25,000 to 18,300 to better reflect actual operating conditions. The 2,000 cycles (from Table 3-3 of WCAP-12191, Revision 3) listed in Table 4.3-1 relate to the RCS cycles which correspond to 18,300 (from Table 6.1-2 of Westinghouse Calculation Note CN-SGDA-02-214) (25,000 for the original steam generators) feedwater cycles experienced by the steam generators, primarily the feedwater nozzles. WCAP-12191, Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Report for Indian Point Unit 2, Addendum 1, September, 2003 CN-SGDA-02-214, 4.7% Uprate Structural Evaluation of Primary and Secondary Side Components for the Indian Point Unit 2 (44F), 10% plugging, 2/25/2005 Section 4.3.1 at the top of LRA Page 4.3-3, will be revised as follows. Feedwater cycling is a transient that affects the replacement steam generators. The steam generators are analyzed for 18,300 cycles. However, the 18,300 cycles do not appear on Table 4.3-1 since these cycles have no significant impact on the RCS. Instead, Table 4.3-1 includes 2000 feedwater cycles. These are cycles that are significant enough to affect the RCS. As part of IPEC Commitment #6, the IP2 procedure will be reviewed to ensure for the feedwater cycles, the number of cycles listed is consistent with the design requirements and to evaluate any necessary changes to the description of the event used in the cycle counting procedure.
11	TLAA 4.3-9 (a) LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. However, LRA Section 4.3.1.1 states "the projected numbers of transient cycles used for reactor vessel fatigue analyses remain within analyzed values," and invoked the 10 CFR 54.21(c)(1)(i) for its reactor vessel TLAA. Please justify this conclusion. The response should clarify whether there are certain events that do not contribute to fatigue usage of the reactor vessel. (b) The LRA indicates that no transients applicable to the reactor vessel are projected to exceed their analyzed number. Verify that the Loss of Load transient, predicted to reach 12 cycles with only 10 allowed, was not used in analysis of the reactor vessel. Provide the basis (reference) for your response.	(a) The transients in Table 4.3-1 that exceed the analyzed numbers are in the "Other Events" category. These events do not contribute to the reactor vessel fatigue. Thus the vessel fatigue analysis remains valid. The exception is steady state cycles. Reevaluation of the number of steady state cycles is included in Commitment 6. Since the Fatigue Monitoring Program assures that the analyzed numbers of cycles are not exceeded, IPEC will clarify LRA Section 4.3.1.1 to show that the effects of fatigue will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii). Section 4.3.1.1 will be revised to read as follows. 4.3.1.1 Reactor Vessel The reactor pressure vessel (and appurtenances) fatigue analyses were performed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition, 1966 and 1967 addenda. (A complete listing of applicable codes is given in Tables 4.1-9 of the IP2 and IP3 UFSARs.) The existing fatigue analyses of the reactor vessel are considered TLAA because they are based on numbers of cycles expected in 40 years of operation. The CUFs for the reactor pressure vessel are given in Table 4.3-3 for IP2 and Table 4.3-4 for IP3. Design cyclic loadings and thermal conditions for the reactor pressure vessel were originally defined in the design specifications and analyzed in the original vessel stress reports. These analyses have been occasionally revised, most recently for the extended power uprate. These latest analyses are reflected in the current UFSAR tables. As described in Section 4.3.1, the projected numbers of transient cycles used for reactor vessel fatigue analyses remain within analyzed values. The effects of fatigue on the reactor vessel will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3. (b) The 10 loss of power transients listed for IP2 in LRA Table 4.3-1 are loss of the turbine generator bus followed by reactor and turbine trips. LRA Table 4.3-1 will be revised to clarify the definition of loss of power transients. These transients are not used in the reactor vessel fatigue analyses for either unit, and are not listed in either FSAR Table 4.1-8 or in LRA Table 4.3-1 for IP3. Loss of power is not included in the original OEM stress report for IP2 nor is it included in the design transients that support the power uprate (C&MS/POAC(02)-007CN, "Design Transient Revisions for Indian Point 2.4% Uprating," Revision 1, March, 2005). Therefore the statement that "the projected numbers of transient cycles used for reactor vessel fatigue analyses remain within analyzed values" is a valid statement. Loss of power events were added to the IP2 cycle counting procedure because there are 40 loss of power transients analyzed in the power uprate analysis for the IP2 steam generators [SGDA-02-214, "4.7% Uprate Structural Evaluation of Primary and Secondary Side Components for Indian Point Unit 2 (44F), 10% Plugging," Revision 0, February, 2005]. As part of License Renewal Commitment 6, IPEC will determine why there are only 10 loss of power events in the IP2 transient monitoring procedure while 40 are assumed in the analysis. The Fatigue Monitoring Program will continue to manage the effects of fatigue by counting these cycles and requiring

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		action to be taken if the actual number of cycles approaches the cycles allowed by the procedure. Clarification to be incorporated into the LRA
12	TLAA 4.3-10 As described in LRA Section 4.3.1.2 through LRA Section 4.3.1.8, in light of IP2 design transients whose 60-year projections exceed the design cycles, the applicant made same statement (refer to the previous question) for the fatigue analyses of the associated components. Please justify the conclusion for each component. Is the loss of power event considered in the reactor vessel internals CUFs? What is the basis (reference) for this answer.	The transients associated with the charging system do not affect the reactor vessel internals (Section 4.3.1.2), pressurizer (Section 4.3.1.3), steam generators (Section 4.3.1.4), reactor coolant pumps (Section 4.3.1.5), or control rod drive mechanisms (Section 4.3.1.6). These TLAA remain valid as stated as long as the analyzed values for the relevant transients are not exceeded. Since the FMP is relied on to assure that the numbers of transients do not exceed the analyzed values, IPEC will credit the FMP for managing the effects of aging for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). As described in Section 4.3.1.7, the regenerative heat exchanger TLAA is projected based on a component specific analysis and extrapolation of the transients incurred at the time of that analysis. The projected CUF based on the projected number of cycles, 0.13, is well below the limit of 1.0 such that a detailed re-analysis is not required. The charging nozzles are more limiting than the heat exchangers and consequently there is no fatigue analysis for the heat exchangers. In Section 4.3.1.8, only the charging system piping is affected by the charging system transients. As described in Section 4.3.1.8, the charging system piping may exceed its analyzed number of transients. This piping, including the charging nozzle, will be reevaluated with the other NUREG/CR-6260 locations as discussed in LRA Section 4.3.3. The latest IP2 reactor vessel internals fatigue analysis is in calculation RCDA-03-51 Revision1, which in turn references Westinghouse Letter LTR-SSO-03-043, Rev 1, dated April 25,2003, "Design Transient Revisions for Indian Point Unit 2 4.7% Uprate Program. This letter is internal Westinghouse correspondence that is not available on site. The latest IP3 reactor vessel internals fatigue analysis is in calculation RCDA-03-108 which in turn references Westinghouse Letter LTR-SCS-03-053, "Design Transient revisions for Indian Point 3 Stretch Power Uprate Project – Revised Figures", dated August 21, 2003. There is no loss of power event in this reference. Loss of power was a transient considered in the fatigue analyses for the replacement steam generators. LRA Sections 4.3.1.2 thru 4.3.1.7 and all sub-parts of Section 4.3.1.8 except ANSI B31.1 piping will be revised to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). (See the response to question TLAA-4.3-9 for an example.) LRA Tables 4.1-1 and 4.1-2 will be revised to reflect the changes in Sections 4.3.1.2 thru 4.3.1.8. LRA Sections A.2.2.2.1 and A.3.2.2.1 will be revised to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). Clarification to be incorporated into the LRA.
13	TLAA 4.3-11 LRA Table 4.3-7 lists CUFs for various subcomponents of IP2 pressurizer. The applicant concludes: "None of the design transients used in the analysis of the pressurizer will be exceeded as discussed in Section 4.3.1. The pressurizer fatigue analyses will thus remain valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i)." (a) Since Table 4.3-7 did not consider insurge/outsurge, explain how you reach the above conclusion. (b) Table 4.3-7 shows that in general the IP2 CUFs for the pressurizer are higher than the IP3 CUFs in Table 4.3-8. Discuss why the IP3 CUF will be representative of the IP2 CUF for the pressurizer surge line nozzle. Are there basis documents (references) to support these CUFs?	(a) Table 4.3-7 lists the CUFs of record for the IP2 pressurizer. These CUFs, from the fatigue analyses of record in the current licensing basis, do not assume insurge/outsurge transients. The LRA states that this analysis of record (a TLAA) will remain valid for the period of extended operation because nothing associated with 20 more years of operation invalidates the analysis. (b) The latest IP3 pressurizer fatigue analysis (CN-SGDA-03-118, "Evaluation of the Indian Point Unit 3 Pressurizer for the 4.8% Uprate Program," September 2003) updated CUFs for the spray nozzle, the upper shell, and the SRV nozzle but did not update the CUF for the surge nozzle. The CUF of record for the IP3 surge nozzle comes from NYPA calculation IP3-CALC-RCS-00568, "Calculation of Pressurizer Fatigue Usage Factor from WCAP-13491," January, 1993. This utility analysis is based on WCAP-13491, "Evaluation of the Effects of Insurge/Outsurge Transients on the Integrity of the Pressurizer at New York Power Authority's Indian Point Unit 3," October 1992. WCAP-13491 calculated the CUF at 0.4319 at that point in time, considering the insurges and outsurges that had occurred during the 40 plant heatups that IP3 had experienced. IP3-CALC-RCS-00568 extended the CUF calculation in WCAP-13491 to the 40 year life of the plant by conservatively assuming insurges and outsurges would occur during the remaining 160 heatups that remained to reach the 200 heatups previously analyzed for fatigue. IP3-CALC-RCS-00568 calculated a 40 year CUF of 0.9612. The review of the IP2 pressurizer for the recent power uprate (CN-SGDA-03-57, Rev. 1, "Evaluation of the Indian Point Unit 2 Pressurizer for the 4.7% Uprate

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		Program," October 2003) updated CUFs for the spray nozzle, the upper shell, and the SRV nozzle. It did not update the CUF for the surge nozzle. The CUF of record for the IP2 surge nozzle remains 0.264 as calculated in WNET-108, "Consolidated Edison Company Pressurizer Stress Report," April 3, 1969. WNET-108 does not account for insurge/outsurge. If the IP2 surge nozzle was to be reanalyzed for insurge/outsurge, it is expected the resulting increase would be similar to the increase for IP3. Since both plants had CUFs of 0.26 (0.2589 and 0.264) without insurge/outsurge, then both would be expected to have CUFs of approximately 0.96 for 200 heatups with insurge/outsurge. However, this analysis was not performed for IP2. Both the IP2 and IP3 surge nozzles must be re-evaluated for environmentally assisted fatigue and IPEC has committed to that re-analysis prior to the period of extended operation. That re-analysis will include not only environmental factors, but also the effects of insurge/outsurge for both units. Section 4.3.1.3 (bottom of page 4.3-13 to top of page 4.3-14) will be revised to include the following points from the above discussion. If the IP2 surge nozzle was to be reanalyzed for insurge/outsurge, it is expected the resulting increase would be similar to the increase for IP3. Both plants had CUFs of approximately 0.26 (0.2589 and 0.264) without consideration of insurge/outsurge, both would have CUFs of approximately 0.96 for 200 heatups with consideration of insurge/outsurge. However, no TLAA to address insurge/outsurge exists for IP2. Both the IP2 and IP3 surge nozzles will be re-evaluated for environmentally assisted fatigue prior to the period of extended operation. That re-analysis will be performed under the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) and will consider not only environmental factors, but also the effects of insurge/outsurge for both units. Clarification to be incorporated into the LRA.
14	TLAA 4.3-12 LRA Table 4.3-2 does not provide the actual cycles as of 3/21/2006 for "Plant Heatup at 100F per hour" and "Plant Cooldown at 100F per hour." (a) What are the actual occurrence as of 3/31/2006? Please clarify why there are no longer any hydrostatic tests required or performed at IPEC. (b) Why do these two transients use a different extrapolation method, which was projected based on the operating history (1975-1995), in determining the 60-year projection. (c) (Added during breakout meeting during site audit.) Add a note to the LRA that the hydro tests are no longer required by the ASME Section XI ISI program.	(a) At the time the LRA was prepared, the IP3 cycle count for plant heatups and plant cooldowns had only been reduced from the raw data through 12/31/1995. Thus, this data was used in the LRA. A review of additional data shows there were approximately 15 additional heatup/cooldown cycles from 1/1/1996 through 3/31/2006, bringing the total to 55. (b) The LRA projection was done based on the data through 1995 because that was the data readily available. Subsequently additional data through 3/31/2006 has been identified and evaluated resulting in a new projection of 109 heatups/cooldowns in 60 years, versus the 120 projected in the LRA. LRA Table 4.3-2 will be amended to show these revised values. The reduced rate of occurrence of heatups/cooldowns from 1996 to 2006 confirms that the rate of occurrence of cycles was higher early in plant life, making projections based on recent years more realistic. The projection of cycles is not relied on to assure code compliance. As described in LRA Section B.1.12, the Fatigue Monitoring 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. (c) Section XI of the ASME Code, Inservice Inspection, has been modified such that leak tests are now specified instead of hydrostatic tests. Footnote 2 to LRA Tables 4.3-1 and Footnote 3 to LRA Table 4.3-2 will be revised to say these hydro test projections reflect changes to ASME Section XI. Clarification to be incorporated into the LRA.
15	TLAA 4.3-13 On page 4.3-18, the LRA describes IP2 and IP3 responses to NRC Bulletin 88-11, indicating that changes were made to its operating procedures. (a) Discuss the modified operating procedures used to mitigate the pressurizer insurge/outsurge transients. (b) Is the mitigation strategy factored into the	(a) IP2 and IP3 instituted operating changes consistent with the generic Westinghouse program to address surge line thermal cycling. There were two main changes. First. A continuous (reduced flow) pressurizer spray was established. This minimized the temperature differential between the RCS, the pressurizer, and the surge line, thereby reducing the thermal stresses associated with an insurge. Second. Startup procedures were changed to eliminate drawing and then collapsing a pressurizer bubble to run reactor coolant pumps to sweep air out of the

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	determination of IP3 pressurizer surge line nozzle CUF of 0.9612? How was the fatigue usage prior to the use of modified operating procedures captured in the fatigue evaluation? (c) What plant procedures were modified to minimize the effects of pressurizer insurge and outsurge? Does the actual plant data before and after these changes were made support that these changes reduced the occurrence and the severity of these transients? Please provide the revised procedure so that the onsite NRC auditors can review the changes that were made.	RCS/RPV. The collapsing of this bubble early in the startup procedure had resulted in significant insurges that have now been eliminated. (b) The mitigation strategy was not factored into the determination of the IP3 pressurizer surge line nozzle CUF. The calculation that determined the CUF of 0.9612 assumed the operating conditions that existed prior to implementation of the modified operating procedures. The operating conditions before implementation of modified procedures were conservatively applied to determine both the contribution to the CUF from past operation and the contribution to the CUF due to projected future operation. The delta-T(emperature)s used in the analysis were developed from plant operating records from a number of plants. This historical delta T information was used to represent the prior operating history of the Indian Point units, and to calculate fatigue usage due to future operation. The IP3 surge nozzle CUF of record was calculated in IP3-CALC-RCS-00568, Revision 0, issued in 1993. Prior to this calculation, the CUF of record was the 0.259 calculated in the original stress report for the pressurizer. The original stress report had no analysis of insurge/outsurge. c) Plant procedures that were changed include 2-POP-1.1, "Plant Heatup from Cold Shutdown Condition; 2-POP-3.3, "Plant Cooldown, Mode 3 to Mode 5," 3-POP-1.1, "Plant Heatup from Cold Shutdown Condition," 3-POP-3.3, "Plant Cooldown – Hot to Cold Shutdown." Results of the changes are discussed in Interoffice Correspondence IP-DEM-01-008MC, "IP3 Pressurizer Surge Line Stratification – WR-96-6280-02." The letter notes that after procedure changes, the maximum difference between the pressurizer and surge line and the RCS was 227F, well within the 320F limit. The letter concludes that the procedure changes effectively lowered the delta F and eliminated insurge/outsurge transients. Plant procedures, the interoffice memorandum, and plant data were made available for the NRC auditors to review on site.
16	TLAA 4.3-14 LRA page 4.3-13 states: "The IPEC pressurizers were evaluated for the stretch power uprates and cumulative usage factors were updated." This resulted in no change to the CUF, it remains 0.264. Explain why the stretch power uprates had no impact on the surge line CUF.	The IP2 surge line fatigue analysis was evaluated for SPU as described in the following paragraph from WCAP-16156, "Indian Point Nuclear Generating Unit No. 2, Stretch Power Uprate NSSS Engineering Report," February 2004, Section 5.4.1.2.2. "For the pressurizer surge line, the effect of the design transients with respect to the thermal stratification and fatigue analysis was controlled by the ΔT between the pressurizer temperature and the hot leg temperature. The controlling ΔTs for the pressurizer surge line were associated with heatup and cooldown events that were not affected by the SPU. Therefore, the SPU will have no adverse effect on either the thermal stratification or the fatigue analysis for the pressurizer surge line, and the limiting transients in WCAP-12937 (Reference 8) remain valid." Reference 8 is WCAP-12937, Structural Evaluation of Indian Point Units 2 and 3 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification, May 1991. Section 5.4.1.2.2 of WCAP-16211, "Power Uprate Project, Indian Point Unit 3 Power Plant, NSSS Engineering Report," June 2004 makes the same statement for IP3.
17	TLAA 4.3-15 LRA 4.3.1.7 discusses bounding CUFs for IP2 and IP3 Class 1 heat exchangers and the use of IP2 CUF to project the IP3 CUF. (a) IP2 and IP3 were operated by different organizations for a long time before Entergy took over in 2001 and 2000, respectively. Hence, those heat exchangers have different operating histories. Please justify why IP3 heat exchanger CUF is comparable to IP2's CUF. (b) This LRA section discusses IP2 regenerative letdown heat exchangers, IP2 excess letdown heat exchangers, and IP3 auxiliary heat exchangers. There are, however, no discussion on IP3 regenerative letdown heat exchangers and the excess letdown heat exchangers. Are IP3 auxiliary heat exchangers same as regenerative letdown heat exchangers and the excess letdown heat exchangers? Please explain their	(a) As can be seen by review of Tables 4.3-1 and 4.3-2, IP2 is projected to have more cycles of heatups, cooldowns, and reactor trips than IP3, based in part on IP3 having learned lessons from the early operation of IP2. Based on these projections, it is expected that the IP2 CUF will exceed the IP3 CUF. Conservatively, assume the CUFs are approximately the same. As identified in LRA Section 4.3.1.7, since the IP2 CUF is only 0.13, it follows that the IP3 CUF is also well below the limit of 1. This large margin to a CUF of 1 makes this general statement appropriate. (WCAP-12191 calculated an IP2 CUF of 0.235 based on 2000 thermal cycles; however, the WCAP also noted that only 466 cycles had occurred through 10/31/1999. Projecting this number of cycles through the period of extended operation gives 1072 cycles for a projected CUF of 0.235*1072/2000 = 0.13.) As identified in Commitment 6, enhancements are planned to the IP3 fatigue monitoring program that will provide additional monitoring of the heat exchanger cycling. (b) The term "auxiliary heat exchangers" used (twice) in LRA Section 4.3.1.7 includes the regenerative heat exchanger and the excess letdown heat exchanger. The generic Westinghouse determination that the regenerative heat exchanger is limiting (WCAP-12191) applies equally to IP3 and to IP2. Thus the comparison of the IP3 to IP2 is made in part (a) above. The final two paragraphs of LRA Section 4.3.1.7 will be revised to read as follows. . . . The IP3 auxiliary heat exchangers have no plant-specific evaluation. However,

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	differences.	the similarity in design and operation between the two units indicates the results would be similar. As the projected IP2 CUF is 0.13, it follows that the IP3 CUF would also be well below the limit of 1.0, such that a plant-specific analysis, if performed, would satisfy the code CUF limit. The Fatigue Monitoring Program will count the transients experienced by the units and require action if any analyzed number of transients is approached during the period of extended operation. Thus the aging effects due to fatigue on the Class 1 heat exchanges will be managed for the period of extended operation in accordance with 10CFR54.21(c)(1)(iii). IPEC design documents indicate that the auxiliary heat exchangers are not the limiting components in the CVCS system. The charging nozzles on the cold legs are more limiting. Therefore, monitoring of the charging nozzles will assure acceptability of the auxiliary heat exchangers. Because the charging nozzle is one of the locations identified by NUREG-6260 as requiring environmental adjustments to the fatigue analysis, this nozzle will be evaluated with the other NUREG-6260 locations as discussed in Section 4.3.3. Clarification to be incorporated into the LRA.
18	TLAA 4.3-16 LRA Tables 4.3-13 and 4.3-14 indicate that the following components' environmentally adjusted CUFs are all projected to exceed a value of 1.0 during period of extended operation: IP-2 pressurizer surge line piping, IP2 RCS piping charging system nozzle, and IP-3 pressurizer surge line nozzles and piping. The two tables also indicate that there are no environmentally adjusted CUFs for the RCS piping SI nozzle (IP-2 and IP-3), RHR Class 1 piping (IP-2 and IP-3) and RCS piping charging system nozzle (IP-3). On pages 4.3-22 and 4.3-23, Entergy provides its corrective action plan to address this issue. Please confirm that fatigue usage factors will be developed for these locations and that this corrective action program will be included as a commitment on the Indian Point LRA.	"At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Tables 4.3-13 (IP2) and 4.3-14 (IP3), consistent with the Fatigue Monitoring Program, Detection of Aging Effects, IP2 and IP3 will refine the current fatigue analyses to include the effects of reactor water environment and verify that the cumulative usage factors (CUFs) are less than 1.0. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following. 1. For locations identified in LRA Tables 4.3-13 (IP2) and 4.3-14 (IP3) with existing fatigue analyses valid for the period of extended operation, use the existing CUF. 2. Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component. 3. Representative CUF values from other plants, adjusted to or enveloping the IPEC plant-specific external loads may be used if demonstrated applicable to IPEC. 4. An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF. During the period of extended operation, IPEC may also use one of the following options for fatigue management if ongoing monitoring indicates a potential for a condition outside the analysis bounds noted above. 1. Update and/or refine the affected analyses described above. 2. Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0. Option 1 Details The processes that will be used to develop the calculations for Option (1) are established design and configuration management processes. These processes are governed by Entergy's 10 CFR 50 Appendix B Quality Assurance (QA) program and include design input verification and independent reviews ensuring that valid assumptions, transients, cycles, external loadings, analysis methods, and environmental fatigue life correction factors will be used in the refined or new fatigue analyses. The analysis methods for determination of stresses and fatigue usage will be in accordance with an NRC endorsed Edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III Rules for Construction of Nuclear Power Plant Components Division 1 Subsection NB, Class 1 Components, Sub articles NB-3200 or NB-3600 as applicable to the specific component. IPEC will utilize design transients from design specifications as well as design transient information from typical PWR references to bound all operational transients. The numbers of cycles used for evaluation will be based on the design number of cycles and actual cycle counts projected out to the end of license renewal period (60 years). Environmental effect on fatigue usage will be assessed using methodology consistent with the GALL Report, Rev. 1, that states, "The sample of critical components can be evaluated by applying environmental life correction factors to the existing ASME Code fatigue analyses. Formulae for calculating the environmental life correction factors are contained in NUREG/CR-6583 for carbon

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		and low-alloy steels and in NUREG/CR-5704 for austenitic stainless steels." The Fatigue Monitoring Program tracks actual plant transients and evaluates these against the design transients. Cycle counts show no limits are expected to be approached for the current license term. The Fatigue Monitoring Program will ensure that the numbers of transient cycles experienced by the plant remain within the analyzed numbers of cycles, hence, the component CUFs remain below the values calculated in the design basis fatigue evaluations. If ongoing monitoring indicates a potential for a condition outside that analyzed above, IPEC may perform further reanalysis of the identified configuration using established configuration management processes as described above. Option 1 for refined CUF calculations is consistent with the NRC's recommendations for the periodic CUF updates in the "detection of aging effects" (i.e., program element 4) of GALL AMP X.M1, "Metal Fatigue of the Reactor Coolant Pressure Boundary". Option 2 Details If Option (2) becomes necessary, repair or replacement of the affected components before fatigue usage calculations determine the CUF exceeds 1.0 will be in accordance with established plant procedures governing repair and replacement activities. These established procedures are governed by Entergy's 10 CFR 50 Appendix B QA Program and meet the applicable repair and replacement requirements of the ASME Code Section XI. Repair or replacement of the affected locations is a corrective action. If this option is selected for corrective action, the repair or replacement activities would be in compliance with applicable provisions of the ASME Code Section XI. Since the implementation of repair and replacement activities will be based on applicable ASME Code Section XI requirements, Option (2) is consistent the "corrective actions recommended in GALL AMP X.M1, "Metal Fatigue of the Reactor Coolant Pressure Boundary." Commitment 33 describes IPEC activities under the Fatigue Monitoring Program that will manage environmentally assisted fatigue in accordance with 10 CFR 54.21(c)(1)(iii).
19	TLAA 4.3-17 Regarding TLAA on environmentally-assisted fatigue issues, in Section 4.3.3 of the LRA (page 4.3-22), the applicant states that it will implement one or more of the three options described on that page. Please provide information on the methodology that will be used for the chosen option or options. Specifically, please address the followings: (a) If Option (1) is chosen, describe the methodology and the process that will be used to ensure that assumptions, transients, cycles, external loadings, Fen values, and analysis methods are valid for the refined or new fatigue analyses. In the event the refined analyses performed under Option (1) result in CUFs greater than 1.0, describe the option(s) that may be used in addition to Option (1). (b) If Option (2) is chosen, describe the AMP in sufficient detail with regard to inspection scope, inspection methods, inspection frequency, and inspection qualification techniques. (c) If Option (3) is chosen, describe how the repair or replacement activity will be implemented in accordance with applicable repair or replacement requirements of the ASME Code Section XI.	Close Question 19 to Question 18. A combined response is provided as the Question 18 response.
101	TLAA 4.3-18 (a) In the LRA Tables 4.3 3 and 4.3 4, closure	(a) This change was made in Entergy Calculation R-4147-00-1, "Reactor Vessel Tensioning Optimization Stress Report Indian Point Units 2 and 3", dated 9 March 2005, and covers both IP2 and IP3. Table II-1 of this calculation lists the stresses

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	studs are listed with a cumulative usage factor of 0.944 along with an explanation note that states, "The CUF of the reactor vessel studs was revised based on the optimization of the stud tensioning procedures and a UFSAR change is in process to reflect this revision." Please describe how the revised tensioning process impacted the stress calculation. Please include the specific values of peak stresses, before and after the revised tensioning process. Part (b) came from breakout meetings during the site audit. This was initially in the database as question 136. (b) The NRC would like to review the bases behind Note 1 to LRA Table 4.3-3 concerning the re-analysis of the RPV studs as follows: (1) The new FSAR change that is in progress. (2) The new CUF that is based on the old CUF. (3) The CUFs are based on the old design cycles.	and usage factors before and after the optimization. The revised tensioning process resulted in increased values of peak stress. The main reason for the increased stress is that the revised tensioning procedure relaxed the tolerance for the final elongation of the studs. The maximum stress with the previous procedure was 93.10 ksi while the maximum stress with the revised procedure is 104.1 ksi. Calculation R-4147-00-1 is available onsite for review. (b) 1) The site provided a copy of the pending FSAR change to the NRC auditors for onsite review. 2) The basis calculation for this statement is R-4147-00-1, which was provided to the NRC for onsite review as Reference 9.5.73 to LRD04, the basis document for Section 4.3 of the LRA. The equations that were used to determine the revised stresses are summarized in Section 6 of this calculation. 3) Section III of R-4147-00-1 and the associated Dominion Engineering memorandum discuss using the Westinghouse design transients to perform the fatigue evaluation. Copies of the FSAR change in progress and Calculation R-4147-00-1 were provided to the NRC auditors for onsite review.
102	TLAA 4.3-19 LRA Section 4.3.1.8 states, "The IP2 charging system piping failure analyses determined the limiting CUF for the charging nozzle as 0.99 for number of analyzed transients shown in the last nine entries in Table 4.3 1." (a) Please explain the conservatism behind projecting no transient condition for "the charging flow shutoff with delayed return to service." (b) Please explain why there will be no following transient conditions in the future: letdown flow shutoff with delayed return to service and charging flow shutoff with prompt return to service.	(a) There is no specific conservatism in the assumption of zero cycles of this one particular transient, "charging flow shutoff with delayed return to service", however, conservatism does exist in the analysis from other numbers of transient cycles being less than the analyzed values. Zero projected cycles is realistic based on reviews of plant data that show that this event has not occurred to date. WCAP 12191 Revision 3 "Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Report for Indian Point Unit 2-Addendum 1" provides the basis for the IP2 transient cycles that are tracked in procedure 2-PT-2Y015. Table 2.3-3 of WCAP 12191, indicates the projected number of cycles based on the detailed review of actual plant data through 10/31/99, and shows this projection results in an acceptable CUF. WCAP-12191 Revision 2 had 5 analyzed cycles of charging flow shutoff with delayed return to power. Revision 3 modified the analyzed numbers of cycles based on operating history. While the analyzed number for charging flow shutoff with delayed return to power was reduced to 0, the analyzed numbers for other events were increased. (b) It is not expected that there will be a letdown flow shutoff with delayed return to service nor a charging flow shutoff with prompt return to service during the period of extended operation based on operating experience. The projections are based on the number of occurrences from 1999 through 2005. Since there were no cycles experienced in this time period, the rate used in the projection is zero and thus no additional cycles are projected for the rest of plant life. This is a projected number, not the number that was analyzed to calculate the CUF. The projected values in LRA Table 4.3-1 do not change the analyzed number of cycles. Three (3) letdown flow shutoffs with delayed return to service were analyzed and 101 charging flow shutoffs with prompt return to service were analyzed. The Fatigue Monitoring Program will manage the effects of aging due to fatigue by monitoring the numbers of cycles and requiring action if the analyzed numbers are approached. Note that several of the other charging system transients project above their analyzed numbers, and re-analysis of the charging system is anticipated prior to the period of extended operation. The Fatigue Monitoring Program will determine exactly when that reanalysis is required considering the number of occurrences of all analyzed transients. Also, as identified in LRA Section 4.3.1.8, the charging nozzle is one of the locations requiring environmental adjustments to the fatigue analysis, which will require a reanalysis of this nozzle as discussed in LRA Section 4.3.3. When performing the fatigue analyses, appropriate conservatism will be added to the analyzed numbers of cycles.
112	Section 4.3 of the LRA has no references while other sections and Section 4.3 of other applications do. Why don't we have references for Section 4.3?	IPEC included the references in LRD04, the basis document for LRA Section 4.3. Copies of the LRD04 references were provided to the NRC audit team for onsite review. IPEC will review the key references in LRD04 and add to LRA Section 4.3 any previously docketed references that pertain to that section. References that have not been previously docketed are available on site for review. Clarification to be incorporated into the LRA.

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113	Reference 9.5.79 to LRPD04 is SE&PT-7712. This letter provides CUF estimates for Indian Point 2 based on MT-SME-281 (Ref. 1 to SE&PT-7712). The reference is dated 6/3/1988 and the response was transmitted on 6/24/1988. How was this performed so quickly?	SE&PT-SSAD-7712 was able to be done quickly because it did not redo any of the finite element analyses to determine individual usage factors. Rather it used the existing individual usage factors and merely summed them to estimate the number of transients that had occurred to that point in time. SE&PT-SSAD-7712 does not calculate design CUFs based on design cycles. Rather, it estimated the CUFs at that point in time. This calculation was part of a larger project that also included WCAP-12191. This calculation was to determine which plant components had the largest actual CUFs in order to develop the functional requirements for a transient and fatigue cycle monitoring system; however, no such system was ever installed. Note that LRPD04, Section 2.5.9 concludes that this report does not calculate design CUFs and therefore is not a calculation of record, and therefore is not a TLAA. Thus, this report is not mentioned in the license renewal application.
114	Why is MT-SME-281 quoted for design cycles in Reference 9.5.79 to LRPD04 (SE&PT-7712) instead of an E-spec? Does IPEC have an equipment specification or design specification for piping?	SE&PT-SSAD-7712 does not use an E-specification for input because it was not attempting to calculate design CUFs based on design cycles. Rather, it determined the CUFs at that point in time based on the transients that had occurred to date. The input document (MT-SME-281) provided the transients to date. The cycles quoted were actual cycles, not design cycles. This calculation was part of a larger project that also included WCAP-12191. The calculation was to determine which plant components had the largest actual CUFs in order to develop the functional requirements for a transient and fatigue cycle monitoring system; however, no such system was ever installed. Note that LRPD04, Section 2.5.9 concludes that this calculation does not calculate design CUFs and therefore is not a calculation of record, and therefore is not a TLAA. Thus, this report is not mentioned in the license renewal application. IPEC does have an equipment specification for piping. The specification was provided for onsite review.
115	Note 2 to Tables 4.3-13 and 4.3-14 states that RCS piping is designed to ANSI B31.1 and no fatigue analyses were performed and no CUFs were calculated. Does the applicant intend to calculate CUFs for these locations?	As stated in LRA Section 4.3.3, Entergy intends to calculate the CUFs for subject B31.1 locations, including consideration of the effects of reactor water environment, at least two years prior to the period of extended operation.
116	IP2 LRA Table 4.3-13 has 2 components on the NUREG-6260 list that have no CUF while IP3 LRA Table 4.3-14 has 3 components that have no CUF. Please explain this difference between units.	Neither unit (IP2 nor IP3) had CUFs for three locations (the charging system nozzle, the safety injection nozzle, or the RHR class 1 piping) as part of the original design. All of these locations were built to USAS B31.1 rather than ASME III. After a period of operation, IP2 noticed that they were using the charging system nozzle at a higher rate than recommended by the OEM. (I.e. they weren't using the alternate charging nozzle as frequently as was recommended.) Consequently, IP2 performed a fatigue analysis of the charging nozzle to assess the effect of this operation. The result of that analysis is quoted in LRA Table 4.3-13. IP3 did not perform such a calculation and they therefore have no corresponding CUF in Table 4.3-14.
117	IP3 Section 4.3.1.8 of the LRA discusses the IP2, loop 3 accumulator nozzle. Explain in more detail why an analysis was done for this specific nozzle and not the other accumulator nozzles on IP2 and IP3	As stated in LRA Section 4.3.1.8, these nozzles were designed and built to USAS B31.1 and did not require the calculation of a CUF. However, after a period of operation, IP2 discovered that the Loop 3 accumulator nozzle thermal sleeve was no longer in place. IP2 performed a fatigue analysis of this nozzle (without a thermal sleeve) to show that it was acceptable for service in that condition. The analysis was done specifically for this one nozzle and does not apply to the remaining nozzles as the thermal sleeves remain in place.
118	The final paragraph of LRA section 4.3 discusses options for dispositioning a flaw, which include analysis or repair. Why did the applicant not include replacement as an option.?	The subject paragraph will be revised to include the replacement option as follows. Fracture mechanics analyses of flaws discovered during in-service inspection may be TLAA for those analyses based on time-limited assumptions defined by the current operating term. When a flaw is detected during in-service inspections, the component may be replaced, repaired, or evaluated for continued service in accordance with ASME Section XI. These evaluations may show that the component is acceptable to the end of the license term based on projected in-service flaw growth. Flaw growth is typically predicted based on the design thermal and mechanical loading cycles. Clarification to be incorporated into the LRA.
119	LRD04: What are the alert values (i.e. values which trigger the initiation of corrective actions) for	IPEC Procedure 2-PT-2Y15 calculates "alert levels" by adding twice the number of cycles that occurred in the last fuel cycle to the total number of cycles to date.

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	the Fatigue Monitoring Program.	Corrective action is initiated if this alert level exceeds the number of analyzed transients. In other words, if the number of cycles is projected to remain at or below the analyzed level for 2 additional fuel cycles, no corrective action is required.
120	Related to Question 4.3-1, Item #3 (a) For reactor trips, IP2 based the cycle projections on the recent 6 years of operation while the cycle projections for all other events are based on the full operating term. Why the difference? (b) The LRA should be amended to include the revised projections provided in the first response to this question. c) Explain why it is acceptable to use a linear extrapolation to project transients.	This question was a clarification to Question 3. The response has been incorporated into the response to Question 3. This question should be closed and the issue resolved via Question 3.
121	*Relative to existing question TLAA 4.3-5, the* second half of the question is 7(c) and it should be 7(b). Answer question in more detail, with references. In particular, address whether or not steady state oscillations are significant to the existing fatigue analyses (b) The second half of the question should be (b), not (c) Answer the second part more clearly, with references. Explain whether or not steady state oscillations are important in the fatigue analysis.	*The response to this question has been incorporated into the response to database* question #7, TLAA 4.3-5. This question should be closed to question #7.
134	Item 14 on LRA Table 4.3-2 gives the number of events (5) for the Operating Basis Earthquakes rather than the number of cycles. Please provide the number of cycles that were analyzed.	Table 4.3-2 is for IP3, and IP3 FSAR Table 4.1-8 states that there are 10 cycles in every earthquake event. The footnote from FSAR Table 4.1-8 will be added to LRA Table 4.3-2 as follows: 5. The upset conditions include the effect of the specified earthquake for which the system must remain operational or must regain its operational status. The faulted conditions include the earthquake for which safe shutdown is required. For fatigue studies, Class I components were analyzed for five OBE's and one DBE in addition to other fatigue producing events in the above listed four loading conditions. Each earthquake is considered to produce ten peak stress magnitudes. Clarification to be incorporated into the LRA.
135	Note 1 to LRA Tables 4.3-13 and 4.3-14 needs to be revised. Please verify this statement is correct and make it clearer which nozzles are being discussed.	The note will be clarified as shown below. Also the footnote in the table is moved from the pressurizer surge line nozzle to the surge line piping to better show that 0.6 is the bounding CUF for the pressurizer surge lines. 1. The maximum usage factor on Indian Point surge lines occurred at the pipe side of the pressurizer nozzle safe end with a value of 0.60. (Section 5.4 of WCAP-12937, "Structural Evaluation of Indian Point Units 2 and 3 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification," May, 1991). Clarification to be incorporated into the LRA.
136	The NRC would like to review the bases behind Note 1 to LRA Table 4.3-3 concerning the re-analysis of the RPV studs as follows: a) The FSAR change is in progress. b) The new CUF is based on the old CUF. c) The CUFs are based on the design cycles	This question is a followup to question 101. This question should be closed and the answer tracked in 101.
137	Table 4.3-3 says the CUF for the IP2 core support pad is 0.904 while Table 4.3-4 says the CUF for the IP3 core support pad is 0.052. Please explain this large difference between the two units.	The primary reason for the difference in CUF is the difference in the analytical methods (i.e. plant specific vs. multi plant bounding analysis). For IP2, the core support pad was evaluated in a calculation which also included Diablo Canyon and Salem. This evaluation used the limiting geometry for the core support pad. The

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		Diablo Canyon geometry (two supports joined by a ligament) was significantly more limiting than the IP2 geometry (individual supports welded directly to the vessel wall). The resulting CUF was based on the Diablo Canyon geometry and is thus higher than a realistic CUF for IP2. For IP3, the evaluation was performed solely for the specific IP3 geometry and therefore it did not include the added conservatism introduced as a result of evaluating a more limiting geometric configuration.
138	The extrapolation of Reactor Trips with excessive cooldown in Table 4.3-1 projects only 159 events after 60 years even though there are 148 events to date. Please explain this projection in more detail.	Based on the response to Item 120, the LRA will be amended to show 160 events instead of 159. This amendment will be included in the response to Question #3. The reactor trips with excessive cooldown were projected based on data from 1999 to 2005. There were only 2 transients recorded during this time. There were 2,032 days in this time span, but 336 days were removed because that time was spent in a steam generator replacement outage. The resulting rate was still only 0.00118 cycles per day, which projects to 160 cycles in 60 years of operation. (160.21) The fatigue monitoring program will continue to monitor the number of reactor trips with excessive cooldown and require action if the analyzed number of cycles is approached.
139	Table 4.3-2, item 11, is for an infinite number of steady state cycles. Please identify the delta-Temperature associated with these cycles.	The exact values of temperature and pressure involved in these steady state cycles varies among references. The temperature change is stated as ±3°F and as a 6°F change. The stated pressure change varies from 25 psig to 100 psig. The conservatively bounding variation is a 6°F change with a 100 psi pressure change. This question will be closed to Question #9.
140	LRA Section 4.3.1.2 states that the reactor vessel internals were designed to meet the intent of Subsection NG of ASME Section III. Please explain what this means.	Subsection NG to ASME III did not exist when the IP2/IP3 internals were designed. The statement in question was taken directly from WCAP-16156, "Indian Point Nuclear Generating Unit No. 2, Stretch Power Uprate, NSSS Engineering Report", dated February 2004. This statement means that when the internals were reviewed for the power uprate, they were found to be designed and built in essentially the same way that internals would be built today, if built in accordance with Section NG. It says it meets the "intent" of Section NG because while the construction is similar, the documentation of material, inspections, and analyses were not to Section NG requirements.
141	These comments are relative to the pressurizer analysis discussed in LRA Section 4.3.1.3 on pages 4.3-12 and 4.3-13 a) What is the basis document for the pressurizer analysis discussed in LRA Section 4.3.1.3 on page 4.3-12? Please provide a copy of this calculation. b) There appears to be an extra "the" in the last paragraph on page 4.3-12. c) Verify the second sentence on page 4.3-13 (the surge and spray nozzles were analyzed) d) Amend the LRA as needed for items a) through c)	a) The basis document for LRA Section 4.3.1.3 is WNET-108. This was reference 9.5.67 to LRD04, the fatigue report basis document. A copy of the reference was provided to the NRC for onsite review. B) There is an extra "the" in the first sentence of the last paragraph. The sentence includes the phrase "of the all transients". The word "the" between "of" and "all" will be removed. That sentence will be revised to read as follows: Section 4.3.1 projected the numbers of cycles of all transients used in the pressurizer fatigue determination, except steady state oscillations, would remain below the numbers analyzed by the stress report through the period of extended operation. C) The second sentence on page 4.3-13 is correct as written. However, this sentence can be misleading and Entergy will reword it as follows. While the original stress report did not analyze the pressurizer shell, it did analyze the surge nozzle and spray nozzle. The resulting CUFs are not the CUFs of record as both the surge and spray nozzles were subsequently re-evaluated for the stretch power uprates. The usage factors of record are given in Tables 4.3-7 and 4.3-8. Clarification to be incorporated into the LRA. (Applicable to parts b) and c).)
142	The following questions refer to LRA paragraph 4.3.1.7 on page 4.3-17. a) LRA paragraph 4.3.1.7 says the regenerative letdown heat exchangers are qualified to 2000 cycles. Explain what these 2000 cycles are. b) Clarify the statement that the CUF of 0.13 does not require a plant specific analysis. c) Clarify the statement that charging nozzle is limiting. Does this refer to the nozzle in the heat	a) While the FSAR says the regenerative heat exchanger is qualified to 2000 cycles, Section 2.4 of WCAP-12191, Addendum 1 to Revision 3, goes into greater detail and shows that the heat exchanger is analyzed to the following cycles. 1. 2000 step change in shell side fluid from 100 deg F to 560 deg F (stops and starts of charging and letdown) 2. 24000 step change in shell side fluid from 400 deg F to 560 deg F (changes in charging and letdown)

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	exchanger or the nozzle in the RCS piping	3. 200 changes in shell side fluid from 100 deg F to 560 deg F over 4 hours (plant heatups and cooldowns) 4. 200 pressurizations of shell and tubes to design pressure (plant heatups and cooldowns) WCAP-12191 states "Furthermore, based on the evaluation of all four transient categories, the design usage is essentially due to Transient Category 1." It does not give individual usage factors for each category of transient, only this summary statement. The description in Section 4.3.1.7 will be clarified as shown below to specify that these cycles represent step changes from 100 deg F to 560 deg F due to stops and starts of charging and letdown. b) The paragraph for the IP3 heat exchangers will be modified as shown below. The change removes reference to a TLAA for IP3 since there is no IP3 analysis. In addition, the paragraph of the section will be revised to say the TLAA for the IPEC regenerative heat exchangers fatigue remains valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i). See the revised section below. c) WCAP-12191 Section 2.4, Conclusion 3, says the charging nozzle is limiting compared to the auxiliary heat exchangers. From WCAP-12191, Section 2.3, it is clear that the nozzles being discussed are the RCS piping nozzles (the normal nozzle in the cold leg and the alternate nozzle in the hot leg). LRA Section 4.3.1.7 will be clarified to specify that the nozzle is the nozzle at the RCS cold leg piping. The LRA will be clarified as shown below to reflect answers a), b), and c). 4.3.1.7 Class-1 Heat Exchangers The original manufacturing equipment specification for the regenerative letdown heat exchangers and the excess letdown heat exchangers says that these heat exchangers are to be qualified for various transients. The E-spec suggests that the manufacturer should verify in writing that all conditions of Paragraph N-415.1 of Section III are satisfied for the transient conditions; otherwise, a fatigue analysis is required. The IPEC UFSARs say the regenerative letdown heat exchangers and the excess letdown heat exchangers are qualified to 2000 temperature cycles from 100 degrees F to 560 degrees F associated with charging and letdown starts and stops. Westinghouse determined that the regenerative heat exchanger was the controlling heat exchanger with regards to fatigue, and therefore only that heat exchanger was analyzed. The associated report concludes that by 10/31/1999, Unit 2 had accumulated 466 of the analyzed 2000 cycles (23.3%) on the regenerative heat exchanger. Further, since the analyzed CUF was only 0.235, the CUF as of 10/31/1999 was equal to 0.235 x 23.3% = 0.05. For license renewal, the thermal cycles seen by the regenerative heat exchanger can be projected through the period of extended operation to show that only 1072 cycles (54%) are expected in 60 years, corresponding to a projected CUF of 0.235 x 54% = 0.13. The IP3 auxiliary heat exchangers have no plant-specific evaluation, and therefore, there is no TLAA. However, the similarity in design and operation between the two units indicates the results would be similar, if an analysis had been performed. As the projected IP2 CUF is 0.13, it follows that the IP3 CUF would also be well below 1.0. Thus the TLAA for the heat exchanger fatigue remains valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i). IPEC design documents indicate that the auxiliary heat exchangers are not the limiting components in the CVCS system. The charging nozzles at the RCS cold leg piping are more limiting. Therefore, monitoring of the charging nozzles will assure acceptability of the auxiliary heat exchangers. Because the charging nozzle is one of the locations identified by NUREG/CR-6260 as requiring environmental adjustments to the fatigue analysis, this nozzle will be evaluated with the other NUREG/CR-6260 locations as discussed in Section 4.3.3. Clarification to be incorporated into the LRA.
143	Section 4.3.1.8 refers to ANSI B31.1 and to USAS B31.1; please be consistent in the naming of the code.	The B31.1 power piping code originated in 1955 as ASA B31.1. In 1967 it became USAS B31.1. It later became ANSI B31.1 and is currently ASME B31.1. The code of record for most of IP2 and some of IP3 is ASA B31.1 (1955) while the code of

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		record for some of IP2 and most of IP3 is USAS B31.1 (1967). Throughout the evolution of this code, the fatigue analysis requirements have remained fundamentally the same, and fundamentally different from ASME Section III fatigue analysis requirements. As the intention here is only to separate B31.1 fatigue analyses from Section III analyses, the distinction between ASA – USAS – ANSI – ASME is not critical to the discussion. Consequently, the LRA will be amended as follows. The discussion above will be added to LRA Section 4.3.1.8. The title of the first subsection of LRA Section 4.2.1.8 will be changed to "B31.1 Piping." In addition, all references to B31.1 in the remainder of the LRA will changed to "B31.1" with no prefix. Clarification to be incorporated into the LRA.
144	These questions refer to LRA Section 4.3-2 on page 4.3-20: a) Shouldn't the title of this section be Non-Class 1 Piping and Component Fatigue rather than just Non-Class 1 Fatigue? b) There are contradictory statements on whether or not there is a fatigue analysis for the RHR heat exchanger. Please resolve this apparent discrepancy. c) If no analysis exists for the RHR heat exchanger, that analysis cannot remain valid. Consider saying there is no TLAA, which may mean deleting the paragraph from the LRA.	(a) The title of Section 4.3-2 will be clarified as shown below to read "Non-Class 1 Piping and Component Fatigue." (b) The contradictory statements will be revised as shown below. (c) The assumption in Section 4.3.2 that the RHR heat exchanger had a TLAA was a conservative assumption based solely on statements in the original equipment specification and the FSARs that the component was designed based on 200 cycles. Given that no fatigue analysis for the residual heat exchangers has been found, there is no basis for the assumption that there is a TLAA for this component. The 200 cycles associated with the component were based on the 200 heatups and cooldowns for the reactor coolant system, and these transients are monitored by the Fatigue Monitoring Program and are projected to stay well below 200 through the period of extended operation (LRA Tables 4.3-1 and 4.3-2). Section 4.3.2 of the LRA will be revised as follows. REVISED LRA SECTION 4.3.2: 4.3.2 Non-Class 1 Piping and Component Fatigue Piping and in-line components The design of ASME III Code Class 2 and 3 piping 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. Therefore, the pipe stress calculations are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Non-piping Components Review of potential TLAAs for IPEC non-Class 1 components identified no TLAA. Clarification to be incorporated into the LRA.
145	There is a commitment on the top of page 4.3-22 to redo the pressurizer fatigue analysis. Be sure there is an official commitment to do this.	The pressurizer re-analysis is included in Commitment 33.
146	The third paragraph on page 4.3-22 states: "At least 2 years prior to entering the period of extended operation, for the locations identified in NUREG/CR-6260 for Westinghouse PWRs of the IPEC vintage, IPEC will implement one or more of the following:" Shouldn't this reference LRA Table 4.3-13 and LRA Table 4.3-14 instead of NUREG-6260?	This paragraph will be modified as follows: 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), IPEC will implement one or more of the following: Closed to question #18.
147	The third paragraph on page 4.3-21 misquotes NUREG-6260, please revise this paragraph. There are no fatigue curves with environmental effects.	The LRA paragraph will be revised to read as follows. "NUREG/CR-6260 identified locations of interest for consideration of environmental effects in several plant designs. Section 5.5 of NUREG/CR-6260 identified the following component locations to be evaluated for the environmental effects on fatigue for IPEC vintage Westinghouse plants. These locations and the subsequent calculations are directly relevant to IPEC." Clarification to be incorporated into the LRA.

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162	TLAA Inservice Inspection - Fracture Mechanics Analyses Section 5.1 (SGN 23R-2) of the basis document (IP-RPT-06-LRD04 Rev. 0) describes the fatigue crack growth evaluation was performed and states that "this TLAA will remain valid for the period of extended in accordance with 54.2(c)(1)(i)". But, the attachment 1 (Listing of potential TLAA and Resolution) of the other basis document (IP-RPT-06-LRD03 Rev. 0) describes the "Inservice Inspection - Fracture Mechanics Analyses" is "Not TLAA" and this TLAA is not incorporated into the LRA. Please explain discrepancy between above two basis documents including LRA.	The crack growth analysis for this flaw shows that after 40 years it could grow from 0.33 inches to 0.3640 inches, which is still well below the maximum allowable 1.00 inches. This analysis, which is based upon the design cycles occurring during those 40 years, actually covers the 40 years from 2006 to 2046. Thus, even though this is a 40 year calculation based on the design operating cycles, it extends through the period of extended operation and thus is not a TLAA. Section 5.1 of LRD04 will be revised to reflect this. LRD03 and the license renewal application remain correct as written.
163	TLAA Inservice Inspection - Fracture Mechanics Analyses The letter in the reference document (9.5.74, COR-06-00178, Assessment of IP2 steam generator feedwater nozzle to shell weld indication) indicated that this assessment was preliminary and will be verified and issued as a final evaluation soon. Please provide the final assessment results for onsite review.	The final assessment was provided to the NRC audit team for onsite review. The final document is Entergy calculation IP-CALC-06-00181 (which includes Westinghouse calculation note CN-PAFM-06-61) dated August 2006.
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 cycling. Entergy will revise two places in the application. Page B-45 and page A-22 to clarify that feedwater cycling is included in the enhancement. Note that commitment #6 to make this enhancement already addresses feedwater cycling. Clarification to be incorporated into the LRA.

ATTACHMENT 5 TO NL-08-057

AMP Audit Database Report

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

NRC AMP Audit - All Items

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1	Section 3.6-1 Describe SBO restoration paths RAI 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 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 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

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	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

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	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.

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	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 corrmrection 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

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		been recently inspected or replaced. No additional inspections were recommended. 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	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.

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	inspection results to demonstrate that the FAC program at Indian Point is effective in managing the aging effect.	The following are more examples of inspection results to demonstrate that the FAC 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	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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	Tube Thinning in Westinghouse Reactors." 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	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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	LRA satisfies the GALL for both IP2 and IP3.	
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	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

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	examination, such as eddy current testing, is not possible. In the existing program, what is currently done if eddy current testing is not possible?	inspection.
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:

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		(i) deformations or structural degradations of fasteners, springs, clamps, or other support items; (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)	The ISI program will continue to be implemented in full compliance with the

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	LRA AMP B.1.18, "Detection of Aging Effects" 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?	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,	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. 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

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	or other appropriate methods including visual based on plant configuration and industry guidance. Explain how visual inspection can detect loosening of bolted cable connections.	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. See audit item #563 for further clarification. 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 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	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

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	inspected. Describe the technical basis for sampling and action taken if a degradation was found on a representative sample.	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.
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)	Consistent with NUREG-1801, XI.M32 each inspection activity includes a

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	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.	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 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	(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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	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, 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	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-

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	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.	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) 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	(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 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

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	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)?	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, 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	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). • 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

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	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).	• 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). 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).

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		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 sufficient to ensure that safety-related and important-to-safety embedded concrete foundations are not exposed to aggressive groundwater.	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. 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

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		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) 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).

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		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 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

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		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) 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.	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 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.

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		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. 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	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.

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	for specified corrosion inhibitor concentration limits.	
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 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?	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.
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	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.

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	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?	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?	PLEASE SEE CLARIFICATION RESPONSE provided in LR #410 (NL-08-014) The foam tanks for IP2 and IP3 are required to comply with the requirements of 10 CFR 50.48. The Fire Water System Program will be enhanced to inspect both IP2 and IP3 foam tanks. 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 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)

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		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 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.

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		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. 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.

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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 acceptable?	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 (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

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		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 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)	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 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

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		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. 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.

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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 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	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

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	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?	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 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.	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 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

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		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.
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 standards. What industry standards form the basis for acceptance criteria at IP2 and IP3?	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 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

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		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 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. The program basis documents will be updated to provide additional details on the scope for each new program. Also, a list of components managed by the new programs will be available for on-site review.
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	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.

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	justification included in the LRA to establish consistency with the GALL report.	
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 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	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

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	2. Review documents summarizing results from past inspections.	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.
358	IP2/IP3 Operating Experience Related to Aging Degradation of Containment Structure, Other Structures, and Structural Components Based on review of the Condition Report summaries listed in IP-RPT-06-LRD05, Revision 1, Table 3.1.3 "Operating Experience Applicable to Structures and Structural Components", the project team identified a number of apparently significant conditions of aging degradation of structures that are NOT identified in the LRA, the PBDs for the StructuresA MPS, or the Structures AERM. The following Condition Report summaries, excerpted from the table, identify the types of structural aging degradation of concern: (I) Water Control Structures Deqradation: CR-IP2-2002-04224 200204224 - Industrial Safety performed a walk down in the Unit 1 Screen well House 5' and found: Loose and spalling concrete in overhead south east side. No evidence of concrete on floor, able to see rusted rebar's in ceiling. CR-IP2-2002-05637 200205637 - *During the Service Water ISI, it was* identified that the ceiling and support structure for	Structures at IPEC are formally inspected on a periodic basis as part of the site's implementation of the Maintenance Rule Program as defined in 10CFR50.65. The inspections are performed by personnel in the Civil Engineering department per Entergy procedure ENN-DC-150. Items addressed in the inspection program include, but are not limited to, concrete and steel components, coatings, masonry walls, supports and attachments. All degradation found during the inspections is documented in a report as required by ENN-DC-150 to allow for future trending. Documentation includes photographs, tabularized descriptions of degradation, completion of checklists and evaluation of existing degradation. Observed degradation from current inspections is compared to degradation from previous inspections to determine if the degradation has progressed. Any degradation that is deemed to require repair is documented in the Condition Reporting Process and Work Orders initiated for the repairs. In addition to the formal inspection process, structures at IPEC are inspected on an ongoing basis by system engineers, operations and maintenance personnel during their routine tours of the facility. Any conditions adverse to quality discovered during these routine inspections are documented in the Condition Reporting System and dispositioned. Specific responses for the CR's listed above are discussed below. CR-IP2-2002-04224 a) This CR identifies area in the Unit 1 screen well ceiling where concrete has become loose (spalled) causing rebar to be exposed and develop surface rust. This has been identified since baseline Structures Monitoring Program (SMP) in 1996. This is an initial construction issue as a result of insufficient concrete cover allowing the bar to exfoliate, expand and pop the concrete cover. b & c) Ceiling was inspected by Civil engineering on 4/23/02. It does not represent any immediate structural safety concern. The steel reinforcing rods are the load carrying components in the bottom part of the concrete slab. The concrete cover that has spalled did not contribute to the overall strength of the slab. Its main *function is to protect the re-bar. The re-bar is exposed and has surface rust but* there is no significant reduction of cross sectional area and therefore no effect on

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	the Service Water Pump Pit is severely degraded. Large chunks of cement were found on the plastic floor grating. CR-IP3-2002-02170 The I-beam steel work along both sides of the discharge canal at the discharge canal bridge is deteriorated, rusted through in many large areas, and bent. CR-IP3-2002-02836 During replacement of the 31 Discharge Canal Oil Boom, the south rail beam as found severely corroded approximately 8" below the water line at low tide, causing the oil boom slider to disengage from the track. CR-IP3-2004-03242 While conducting a Plant Tour, I discovered a hole approximately 6x2" at the south end of the Unit 2 discharge canal directly opposite the Unit 3 Polisher building. This hole was apparently caused by the erosion of the cement near the grating. CR-IP3-2005-03993 During a walkdown of the Unit 3 Intake Structure with the Ultimate Heat Sink NRC Inspector, two pieces of spalled concrete (approximately 1" diameter x 1/2" thick) and same rust / scale were found on top of the mat-covered grating on the 5' elevation.	the strength of the slab. No reduction in load carrying capacity has occurred. d, e & f) The condition of loose concrete was stabilized and work order has been initiated to make the repair. The condition is being monitored until repairs are complete. g & h) No augmented or special inspection is planned for the PEO. Unit 1 screenwell house will continue to be inspected and monitored under Structures Monitoring Program during PEO. CR-IP2-2002-05637 a) Same as CR-IP2-2002-04224 (discussed previously), this CR identifies area in the screen well ceiling where concrete has become loose (spalled) causing rebar to be exposed and develop surface rust. This has been identified since baseline Structures Monitoring Program (SMP) in 1996. This is an initial construction issue as a result of insufficient concrete cover allowing the bar to exfoliate, expand and pop the concrete cover. b & c) Civil design engineering conducted an assessment of the structural adequacy of the reinforced concrete slab of the Service Water Pump Pit area of the Unit No. 2 Intake Structure and established that the slab is operable and capable of performing its intended function. d, e & f) The condition was corrected under Engineering Request response ER-04-2-051. The exposed rebars were cleaned and sealed with cementitious epoxy. The damaged steel supports were repaired or replaced. The condition is being monitored. g & h) No augmented or special inspection is planned for the PEO. The unit 2 intake structure will continue to be inspected and monitored under Structures Monitoring Program during PEO. CR-IP3-2002-02170 a) This CR identifies deteriorated carbon steel I-beam on discharge canal bridge. No previous history was found. b & c) Design engineering performed a walked down of discharge canal from gates to SW backup pumps. It was determined that the there was not any condition that is degraded to the extent implied in the CR. The steel under the south bridge has an area of failed coating witch has some surface rust and bent coating but is does not effect structural integrity of the structure. d, e & f) Based on insignificance of coating degradation and surface rust, no repairs were determined necessary. The condition of these beams is monitored under structures monitoring program. A recent inspection (ref. IP-RPT-07-00034, "Inspection of Unit 3 North and south bridges over discharge canal") confirmed these beams are in good condition. g & h) No augmented or special inspection during PEO. The discharge canal structure will continue to be inspected and monitored under Structures Monitoring Program during PEO. CR-IP3-2002-02836 a) This CR identifies severely south rail of the discharge canal oil boom. No previous history found. b & c) The degraded condition of the south rail caused the oil boom slider to disengage from the track. Equipment is degraded and did not function as designed at very low tide. d, e & f) Work order was initiated. The damaged beam was repaired and the oil boom was restored. The rail is currently in good condition. g & h) No augmented or special inspection during PEO. The discharge canal structure will continue to be inspected and monitored under Structures Monitoring Program during PEO. CR-IP3-2004-03242 a) This CR documents a hole approximately 6x2" at the south end of the Unit 2 discharge canal directly opposite the Unit 3 polisher building. This hole was apparently caused by erosion of the cement on grade concrete (walkway) around the grating in area of discharge canal. No previous history was found. b & c) The spalled concrete in the discharge canal does not adversely affect the required function of the discharge canal to direct discharge flow to the Hudson River, away from the Service Water pumps intake. At the southern end of the Unit 2 Discharge Canal directly opposite the Unit 3 Polisher Building a concrete spall, delaminations of the concrete exist. Other portions of concrete in the area of the discharge canal show degradation caused by chemical attack, as shown in the attached pictures. The Corrective Action requires an assessment as to the reason for the spalls and delaminations, with chemical attack (salt) being considered the most likely reason, an assessment of the depth into the concrete of the damaged concrete matrix, and the selection of the best method to fix the spalls and delaminations, including the selection of a concrete epoxy, or protective coating,

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		with enhanced chemical resistance. For the hole described in CA 001 to CR-IP3-2004-03242, a cut-out of the concrete and dowell installation should be considered. Work Order IP3-04-20717 was initiated to make the repairs. d, e & f) Due to insignificant effect of this condition on discharge canal, no repairs have yet been made. The condition is being monitored until repairs are made. g & h) No augmented or special inspection is planned for the PEO. The discharge canal structure will continue to be inspected and monitored under Structures Monitoring Program during PEO. CR-IP3-2005-03993 a) This CR identifies that during a walkdown of the Unit 3 Intake Structure with the Ultimate Heat Sink NRC Inspector, two pieces of spalled concrete (approximately 1" diameter x 1/2" thick) and same rust / scale were found on top of the mat-covered grating on the 5' elevation. The deteriorated concrete condition in this area was previously identified during Maintenance Rule walkdowns (Ref. IP-RPT-03-00090). b & c) The Ultimate Heat Sink/Service Water SSC was evaluated with respect to the following : FME in service water bay - Due to presence of FME mat on grate, there is no chance spalled pieces of concrete can enter the suction bells of the SW pumps. Structural integrity of bay - There is no indication of structural failure. Spalled pieces of concrete are small and do not represent structural failure. No operability issues with ultimate heat sink or service water SSC. Not reportable per ENN-LI-108. d, e & f) Work orders IP3-05-21329 and IP3-05-21330 have been initiated to make any necessary repairs. No repairs have been determined necessary at this time. The structure is being monitored as part of routine inspections under Structures Monitoring Program. g & h) No augmented or special inspection during PEO. The intake structure will continue to be inspected and monitored under Structures Monitoring Program during PEO. No other significant existing conditions of structural aging were identified.
359	IP2/IP3 Operating Experience Related to Aging Degradation of Containment Structure, Other Structures, and Structural Components Based on review of the Condition Report summaries listed in IP-RPT-06-LRD05, Revision 1, Table 3.1.3 "Operating Experience Applicable to Structures and Structural Components", the project team identified a number of apparently significant conditions of aging degradation of structures that are NOT identified in the LRA, the PBDs for the StructuresA MPS, or the Structures AERM. The following Condition Report summaries, excerpted from the table, identify the types of structural aging degradation of concern: (II) IP2 Reactor Cavity Leakaqe: CR-IP2-2002-10610 CR IP2 2002-10052 concerning reactor cavity leakage did not address the following issues: 1) Evaluate/investigate the structural long term effects of the boric acid on the concrete and carbon steel rebar within the concrete. CR-IP2-2003-00682 The Unit Two Refueling Cavity Liner has experienced cracks on numerous occasions. The SOER 02-4 investigative team has discovered that the cracks have been repaired several times. Yet, cracks continue to appear. CR-IP2-2003-00959 THIS IS A SOER 02-4 RESPONSE ISSUE IP-2 has a long-term degradation issue with leakage from the Refueling Cavity Liner. The liner	The reactor cavity at Unit 2 has a history of leaking during refueling outages when the cavity is filled with water. Several attempts have been made over the last several outages to mitigate this condition with limited success. Observations made during filling and draining the cavity during the previous outage indicate that the area of the cavity where the leak occurs is in the upper half. Observations also indicate that water that gets behind the stainless steel liner when the cavity is filled has a low resistance flow path to the 46' elevation in containment. This is indicated by the relatively free flow of water observed to start and stop abruptly once certain water elevations were achieved. It was observed that a previous repair patch had pulled away from the liner plate, leaving a gap for water to infiltrate. Repairs will be made to this failed patch area to seal it prior to filling the cavity during the upcoming outage. In addition, a strippable coating will be applied to other suspect areas of the liner during this outage to mitigate the leakage while the cavity is full of water. Based on review of industry experience, minimal time of concrete exposure to the borated water, and testing performed on concrete samples taken from the Unit 2 Spent Fuel Pool walls after discovery of a liner leak, Engineering has concluded that the reactor cavity concrete structure's capability to perform its design basis function has not been compromised as a result of this issue. An action plan is being developed for a permanent fix to this issue. Two technologies are being investigated for the permanent solution. The locations and extent of permanent repair will be based on the effectiveness of the temporary repairs being made during this upcoming outage. It is also anticipated that concrete core samples will be taken from the cavity walls in subsequent outages for analysis. Specific responses to the Condition Reports listed above are discussed below. CR-IP2-2002-10610 a) This CR requests evaluation of long term effect of boric acid on concrete and rebar due to discovery of a borated water leak from the cavity liner during refueling. Reactor cavity has had a history of leakage during refueling activities when the refueling canal is filled (Ref. CR-IP2-2004-05180). B & c) Utilizing industry experience, results of Florida Power & Light testing of reinforced concrete exposed to borated water, core samples taken of fuel pool wall for leak that went unnoticed for 18 months, IPEC concluded that the leak has no significant effect on the concrete or rebar. The evaluation included the consideration that the boric acid leakage is limited to the duration of the cavity flooding and therefore, the duration of the overall exposure of the concrete to boric acid is significantly shorter than that employed in the tests, i.e., weeks or months versus years. As such, it is concluded that the effect of the boric acid leaks is limited in terms of both extent and depth of penetration in the concrete. Thus, the effect of this

has experienced cracks on numerous occasions. The cracks have been repaired several times, but the cracks continue to appear.

CR-IP2-2004-05180

The IP2 Reactor Cavity has a history of serious leakage through the stainless steel liner when the cavity is filled during refuel outages. The cavity liner is made from stainless steel plates plug welded to structural steel and seam welded together.

event (borated water leak) was determined to be minimal on concrete and reinforcing steel.
D, e & f) No repairs or replacement of concrete have been determined necessary. Action to stop or minimize reactor cavity liner leakage during refueling outages is discussed in CR-IP2-2004-05180.
g & h) No augmented or special inspection planned for the PEO. The rector cavity concrete, and internal structure to containment structure, will continue to be inspected and monitored under Structures Monitoring Program during PEO.

CR-IP2-2003-00682
a) This CR identifies IP2 refueling cavity leakage through the stainless steel liner when the cavity is filled during refueling outages. The cavity is filled during refueling activities and other times it remains dry. The source of the leak was a pinhole leak in a weld area, and was successfully repaired. The identified cause of the pinhole was poor workmanship during original welding of the liner plate which had gone undetected.
B & c) Refueling cavity is filled only during refueling outages. No immediate corrective action or operability is documented in the CR.
D, e & f) Utilizing industry experience, results of Florida Power & Light testing of reinforced concrete exposed to borated water, and core samples taken of fuel pool wall for leak that went unnoticed for 18 months, IPEC concluded that the leak has no significant effect on the concrete or rebar. As for the liner, the repaired area (discussed in item a above) and other suspect weld areas of the liner plate have been inspected (visual and UT) and tested (vacuum test) with satisfactory results. Other welds were found to be of good quality and free of defect.
G & h) No augmented or special inspection planned for the PEO. The effects of aging on the refueling cavity liner plate will continue to be managed under Water Chemistry Control – Primary And Secondary Program during the PEO.

CR-IP2-2003-00959
a) This CR identifies IP2 refueling cavity leakage through the stainless steel liner when the cavity is filled during refueling outages. The cavity is filled during refueling activities and other times it remains dry. The source of the leak was a pinhole leak in a weld area, and was successfully repaired. The cause of the pinhole was poor workmanship during original welding of the liner plate which had gone undetected.
b & c) Refueling cavity is filled only during refueling outages. No immediate corrective action or operability is documented in the CR.
d, e & f) Utilizing industry experience, results of Florida Power & Light testing of reinforced concrete exposed to borated water, core samples taken of fuel pool wall for leak that went unnoticed for 18 months, IPEC concluded that the leak has no significant effect on the concrete or rebar. As for the liner, the repaired area (discussed in item a above) and other suspect weld areas of the liner plate have been inspected (visual and UT) and tested (vacuum test) with satisfactory results. Other welds were found to be of good quality and free of defect.
g & h) No augmented or special inspection during PEO. The effects of aging on the refueling cavity liner plate will continue to be managed under Water Chemistry Control – Primary And Secondary Program during the PEO.

CR-IP2-2004-05180
a) This CR identifies IP2 reactor cavity leakage through the stainless steel liner when the cavity is filled during refueling outages. The cavity is filled during the refueling activities and at other times remains dry. The cavity is known to have leaked since early 1990's. Engineering evaluation of the leakage determined that the liner seam, plug and structural attachment welds on the west wall were the most likely sources of the leakage. The cavity goes through fuel handling operation during refueling outages. Damage to the liner is determined to have occurred during previous refueling outages due to poor cleanliness and maintenance control. This includes use of improper material and tools (wire brush contaminated with carbon steel and containing chloride coming in contact with stainless steel. And, damage (cut) into the liner plate when removing (cutting out) temporary attachments to the liner.

b & c) Since all loose pieces were removed from the wall, the probability for debris to foul equipment in the VC is minimal. Based on the response to CA-1 and since the repair has been made to the wall, the system is operable. Approximately one half of a four foot section within a fifteen foot long patch was loose from the liner wall. It took several attempts with a scraper to pry it free from the wall. During normal operation or a Design Basis Accident this patch would have remained in place. Even if it had fallen, any pieces would have remained in the upper cavity along the West wall and would not have affected any operating equipment or blocked water flow to the sump. Therefore; there was no operability concern.
Evaluation of effect of leak on concrete is addressed by CR-IP2-2002-10610.

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		d, e & f) Liner has gone through numerous inspections and tests. Attempts have been made to repair and stop the leak. Repair attempts have not completely stopped the leak which occurs only while the cavity is filled during refueling outages (at all other times, the cavity is dry). Leak rate has lessened due to the repair attempts. Efforts continue to stop leak through the application of various permanent and temporary repairs. g & h) No augmented or special inspection during PEO. The rector cavity concrete, and internal structure to containment structure, will continue to be inspected and monitored under the Structures Monitoring Program during PEO. No other significant existing conditions of structural aging were identified.
360	IP2/IP3 Operating Experience Related to Aging Degradation of Containment Structure, Other Structures, and Structural Components Based on review of the Condition Report summaries listed in IP-RPT-06-LRD05, Revision 1, Table 3.1.3 "Operating Experience Applicable to Structures and Structural Components", the project team identified a number of apparently significant conditions of aging degradation of structures that are NOT identified in the LRA, the PBDs for the StucturesA MPS, or the Structures AERM. The following Condition Report summaries, excerpted from the table, identify the types of structural aging degradation of concern: (III) IP2 Spent Fuel Pool CracklLeak Paths: CR-IP2-2005-03557 This CR initiated by CA&A to copy a manual CR, which is attached to the suggested action section below with the original paper operability review. A hairline crack several feet in length was found at approximately 60 foot level of Unit 2 spent fuel pool. CR-IP2-2005-04433 A remote visual examination of the Spent Fuel Pool liner identified three potential leak paths located on the South West vertical corner weld between approximately 17' and 20' from the top of the pool.	During excavation work in the Unit 2 Fuel Storage Building in support of Dry Cask Storage, a hairline crack was discovered in the spent fuel pool south wall that appeared damp. Samples taken from this wetted crack indicated that the fluid contained radioactive isotopes consistent with fuel pool water. A collection box was installed on the south wall over the wetted crack area to collect and monitor any leakage emanating through this cracked area. Engineering evaluations have determined that the discovered wetted crack and associated leakage has no detrimental effects on the structural capability of the south spent fuel pool wall. Subsequently, accessible areas of the spent fuel pool liner were inspected for degradation that could result in leakage. Inspections included use of robotic cameras, general visual and vacuum box testing. Vacuum box testing was used on areas of the liner that were suspect based on the general visual and robotic camera inspections. None of the suspect areas in the spent fuel pool area failed the vacuum box test, indicating that none of the indications found were actually leaking. This is also substantiated by the fact that tests performed on the isotopes from the wetted crack in the wall showed the isotopes to be older that those currently in the fuel pool. These indications were coated as a precautionary repair. In addition, the spent fuel pool transfer canal liner was also inspected using the same techniques as those used in the spent fuel pool with the addition of UT where applicable. The inspections discovered several indications and one weld defect in the transfer canal liner. The weld defect failed the vacuum box test. All of the defects and indications were repaired. These indications were all the result of original construction poor workmanship issues. As a consequence of the originally discovered wetted crack in the spent fuel pool south wall, a Geotechnical Firm was contracted to study the groundwater flow patterns onsite and recommend locations for the installation of groundwater monitoring wells. Several dozen monitoring wells were installed throughout the site to monitor the groundwater for any contamination. Specifics of the CR's listed above are discussed below CR-IP2-2005-03557 a) This CR identifies a hairline crack on IP2 spent fuel pool (SFP) south concrete wall. No history of this condition was identified. B & c) The hairline non-propagating crack was inspected by supervisor of civil-structural engineering. Hairline crack is typical of type which develops during concrete forming/curing and will not lead to significant breach. Seepage is evident of either pinhole leak in a weld seem of the stainless steel pool interior liner, or seepage that entered the crack during excavation of adjacent/above containment soil. The condition was determined to be non-threatening to structural integrity of the SFP structure. D, e & f) Concrete crack has been temporarily covered with a stainless steel collection box and the drain is routed to the primary auxiliary building (PAB) for periodic monitoring. Utilizing industry experience, Florida Power & Light testing of reinforced concrete exposed to borated water, core samples taken of fuel pool wall for leak that went unnoticed for 18 months to conclude that the leak has no significant effect on the concrete or rebar. The source of leak was determined to be from pinhole leak in the spent fuel pool liner (evaluation of liner plate leak is provided in CR-IP2-2005-04433). G & h) No augmented or special inspection during PEO. The SFP concrete structure will continue to be monitored fro aging effect under structures monitoring program during PEO. CR-IP2-2005-04433 a) This CR identifies 3 potential leakage paths on IP2 spent fuel pool (SFP) stainless steel liner plate welds. The three and three additional indications were vacuum box tested with no indication of thru wall leakage. In addition these 6 locations were coated as preventive measure. Historically, a pinhole leak was found early 90's and

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		repaired successfully. The cause of pinhole was determined to be a poor workmanship during re-rack modification. Specifically, during welding and removal (cutting) activities of temporary attachment to the liner plate. B & c) Level in the SFP is in accordance with ITS requirements. Leakage rate is such that the pool could be filled in a timely fashion if needed to prevent exceeding specification. No operability concern exists. D, e & f) The repaired area and other suspect weld areas of the liner plate have been inspected (remote) and tested (vacuum box) with satisfactory results. No other leaks are identified. g & h) No augmented or special inspection during PEO. The SFP liner will continue to be managed for aging effects under water chemistry control – primary and secondary, and Monitoring of spent fuel pool level per Tech Spec. during PEO. No other significant existing conditions of structural aging were identified.
361	IP2/IP3 Operating Experience Related to Aging Degradation of Containment Structure, Other Structures, and Structural Components Based on review of the Condition Report summaries listed in IP-RPT-06-LRD05, Revision 1, Table 3.1.3 "Operating Experience Applicable to Structures and Structural Components", the project team identified a number of apparently significant conditions of aging degradation of structures that are NOT identified in the LRA, the PBDs for the StructuresA MPS, or the Structures AERM. The following Condition Report summaries, excerpted from the table, identify the types of structural aging degradation of concern: (IV) IP2 Containment Dome Concrete Spalling: CR-IP2-2004-01347 The south side of the Containment dome in the alley between the Fan building and VC about 25 feet up is spalling in about 6-7 places. The rebar is exposed to the elements and is showing signs of rust. The openings into the concrete are about 12-14 inches.	CR-IP2-2004-01347 The VC concrete structure is routinely inspected and evaluated in accordance with the requirements of the ASME IWL program and the acceptance criteria developed in report IP-RPT-08-00016. Several inspections under this program have been conducted to date and all degradation found has been documented and evaluated. Photographs of all degraded areas are taken during each inspection and compared to those from previous inspections to determine whether the degradation is progressing. Enhancements to the documentation of degradation are being implemented to allow for better trending of these areas. These enhancements include, but are not limited to, obtaining critical dimensional data of degradation where possible, use of scaling technologies for photographs taken and use of consistent vantage points for the visual inspections. To date, none of the documented degradation is ongoing based on comparison of data from previous inspections and the identified degradation poses no threat to the ability of the VC concrete structure to perform its design basis function. Details regarding the specific conditions for this CR are provided below. a) This CR identifies area on IP2 containment where concrete has spalled exposing reinforcing steel showing rust. This condition was noted during the 2000 IWL inspection. The 2005 IWL inspection found little or no change of the condition observed in 2000. b & c) The findings following the inspection by design engineering were evaluated against the information regarding margins contained in the Raytheon report. The evaluation concluded that the locations of the exposed reinforcement, including the areas covered by this Condition Report, are such that even considering further loss of material due to corrosion over an extended period, there is sufficient margin in the design to assure structural integrity of the Concrete Containment under all postulated loads and load combinations. On this basis, the noted deficiencies do not constitute operability or reportability concerns. The spalls occur at locations where cadweld sleeves have insufficient concrete cover attributed to an original installation deficiency. Cadweld splices have diameters larger than the bar and thus have the least amount of concrete cover. Rusting is not active and spalls are in an area where the rebar stresses are low. d, e & f) The condition is being monitored under IWL program. Remedial actions will be taken at any time the spalls degrade further and are found to affect structural integrity. g & h) No augmented or special inspection during PEO. The containment concrete structure will continue to be inspected and monitored under the Containment Inservice Inspection (CII) - IWL Program during the PEO. No other significant existing conditions of structural aging were identified.
410	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?	Audit Item 105 CLARIFICATION REPONSE (original response in LR #105, letter NL-07-153) Audit Item 105 Clarification The LRA amendment for Audit Item 105 communicated in letter NL-07-153, dated December 18, 2007, is replaced with the following. 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.

Item	Request	Response
		Attributes Affected 3. Parameters Monitored or Inspected Enhancements 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. 4. Detection of Aging Effects 6. Acceptance Criteria LRA Section A.2.1.13, Fire Water System Program, fourth paragraph, is revised to add the following. 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.
562	In the series of LRA Tables 3.3.2-19-xx-IP2 and 3.3.2.19-xx-IP3, there are line items that specify "cracking-fatigue" as the aging effect and "TLAA-metal fatigue" as the aging mamagement program. The previously accepted response to audit item 233 stated that the sight glasses 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 was changed to the One-Time Inspection Program by letter NL-07-153 to the NRC dated December 18, 2007. The One-Time Inspection Program is not an appropriate aging management program for "cracking-fatigue" on the carbon steel portions of sight glasses and a different AMP should be cited.	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 will be revised to list the Periodic Surveillance and Preventive Maintenance Program for managing cracking due to thermal fatigue on carbon steel portions of sight glasses. LRA Table 3.4.1, Item 3.4.1-1, and LRA Section 3.4.2.2.1 will be revised to describe use of the Periodic Surveillance and Preventive Maintenance Program to manage cracking due to thermal fatigue on carbon steel portions of sight glasses. LRA section B.1.29 will be revised to inspect the carbon steel portions of sight glasses in the IP2 feedwater, IP3 aux steam and condensate return, IP3 condensate transfer, and IP3 heater drain/moisture separator drains/vents systems. Information to be added to the LRA.
563	Audit item #63 is being clarified to reflect discussion with the NRC staff associated with draft LR-ISG-2007-02.	LRA B.1.22 addresses the plant specific AMP for non-EQ bolted cable connections. Based on discussion with the NRC staff, the AMP discussion for using visual inspection is being clarified to further explain the types of connections and personnel safety issues of opening energized equipment. An example of where visual inspection is acceptable is motor connections where the motor lead is connected to the field cable in a local junction box. Because of personnel safety practices the junction box cover would not be removed when the cable is energized, so thermography could only be performed with the junction box cover in place, which may not provide accurate results. 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. For both of these examples, contact resistance measurements would require the destructive examination of the connection. The Entergy policies for personnel safety for energized components at a potential greater than 600V, are to observe a restricted approach boundary, which would preclude the removal of a bolted cover from energized components at a potential of greater than 600V. The number of bolted connections that are greater than 600V are limited to large motor, transformer, or generator connections (less than 30 connections, which is 3 connections per phase for 10 motors) for both units, and 5 remote MCC for both units. LRA Section B.1.22 was previously revised with Amendment 1, Entergy Letter NL-07-153 dated 12/18/2007, and is not being changed by this clarification.