IPRenewal NPEmails

From: Kimberly Green
Sent: Wednesday, January 14, 2009 2:52 PM
To: STROUD, MICHAEL D; Tyner, Donna
Cc: Sherwin Turk; IPRenewal NPEmails
Subject: Audit Report
Attachments: ML083540625.pdf; ML083540648.pdf; ML083540662.pdf

Mike and Donna,

Attached are the letter, and the two audit reports that were signed yesterday. The signed copy is being transmitted by mail. These documents will be publicly available in ADAMS shortly. The accession numbers are:

ML083540625 (cover letter)
ML083540648 (attachment 1)
ML083540662 (attachment 2)

Should you have any questions regarding these documents, please give me a call.

Kimberly Green
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Hearing Identifier: IndianPointUnits2and3NonPublic_EX
Email Number: 1062

Mail Envelope Properties (83F82891AF9D774FBBB39974B6CB134F7E428AC05A)

Subject: Audit Report
Sent Date: 1/14/2009 2:52:05 PM
Received Date: 1/14/2009 2:52:08 PM
From: Kimberly Green

Created By: Kimberly.Green@nrc.gov

Recipients:
"Sherwin Turk" <Sherwin.Turk@nrc.gov>
Tracking Status: None
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Tracking Status: None
"Tyner, Donna" <dtyner@entergy.com>
Tracking Status: None

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ML083540648.pdf	109568	
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Options
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Expiration Date:
Recipients Received:

January 13, 2009

Vice President, Operations
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249

SUBJECT: AUDIT REPORTS REGARDING THE LICENSE RENEWAL APPLICATION FOR THE INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3, LICENSE RENEWAL APPLICATION

Dear Sir or Madam:

By letter dated April 23, 2007, as supplemented by letters dated May 3, 2007 and June 21, 2007, Entergy Nuclear Operations, Inc., submitted an application pursuant to Title 10 of the *Code of Federal Regulation* Part 54 (10 CFR Part 54), to renew the operating licenses for Indian Point Nuclear Generating Unit Nos. 2 and 3, for review by the U.S. Nuclear Regulatory Commission (NRC or the staff).

During the week of October 8 – 12, 2007, the staff conducted an audit of the scoping and screening methodology. During the weeks of August 27 - 31, 2007, October 22 - 26, 2007, November 27 - 29, 2007, and February 19 - 21, 2008, the staff audited and reviewed selected aging management programs, aging management reviews, and time-limited aging analysis at the Indian Point site. Attached are (1) the "Scoping and Screening Methodology Audit Trip Report," which summarizes the staff's audit activities conducted during the week of October 8 – 12, 2007, and (2) the "Audit Report for Plant Aging Management Programs and Reviews," which summarizes the staff's audit activities conducted during the weeks of August 27 - 31, 2007, October 22 - 26, 2007, November 27 - 29, 2007, and February 19 - 21, 2008. These reports are also accessible from the Agencywide Documents Access and Management System, under Accession Nos. ML083540648 and ML083540662, respectively.

If you have any questions, please contact me at 301-415-1627, or by e-mail at Kimberly.green@nrc.gov.

Sincerely,
\RA
Kimberly Green, Safety Project Manager
Projects Branch 2
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-247 and 50-286

Attachments:
1. Scoping and Screening Methodology Audit Trip Report
2. Audit Report for Plant Aging Management Programs and Reviews

cc w/attachments: See next page

January 13, 2009

Vice President, Operations
Entergy Nuclear Operations, Inc.
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450 Broadway, GSB
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Buchanan, NY 10511-0249

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If you have any questions, please contact me at 301-415-1627, or by e-mail at Kimberly.green@nrc.gov.

Sincerely,
/RA/
Kimberly Green, Project Manager
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-247 and 50-286

Attachments:
1. Scoping and Screening Methodology Audit Trip Report
2. Audit Report for Plant Aging Management Programs and Reviews

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Letter to Entergy from K. Green, dated January 13, 2009

DISTRIBUTION:

SUBJECT: AUDIT REPORTS REGARDING THE LICENSE RENEWAL APPLICATION FOR THE INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3, LICENSE RENEWAL APPLICATION

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SCOPING AND SCREENING METHODOLOGY AUDIT TRIP REPORT

Indian Point Nuclear Generating Unit Nos. 2 and 3

Docket Nos.: 50-247
50-286

SCOPING AND SCREENING METHODOLOGY AUDIT TRIP REPORT FOR THE ENTERGY NUCLEAR OPERATIONS, INC., LICENSE RENEWAL APPLICATION FOR THE INDIAN POINT GENERATING UNIT NOS. 2 AND 3

I. Introduction

During the week of October 8 - 12, 2007, the Division of License Renewal, Engineering Review Branch 2, performed an audit of the Entergy Nuclear Operations, Inc., (the applicant) license renewal scoping and screening methodology developed to support the license renewal application (LRA) for Indian Point Generating Units 2 and 3 (Indian Point). The audit was performed at the applicant's facility located outside Tarrytown, New York. The focus of the staff's audit was on the applicant's administrative controls governing implementation of the LRA scoping and screening methodology and review of the technical basis for selected scoping and screening results for various plant systems, structures, and components. The audit team also reviewed quality attributes for aging management programs, quality practices used by the applicant to develop the LRA and training for personnel that developed the LRA.

II. Background

Title 10 of the *Code of Federal Regulations*, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," Section 54.21, "Contents of Application — Technical Information," requires that each application for license renewal contain an integrated plant assessment (IPA). Furthermore, the IPA must list and identify those structures and components (SCs) that are subject to an aging management review (AMR) from the systems, structures, and components (SSCs) that are within the scope of license renewal. 10 CFR 54.4(a) identifies the plant SSCs within the scope of license renewal. SCs within the scope of license renewal are screened to determine if they are long-lived, passive equipment that is subject to an aging management review in accordance with 10 CFR 54.21(a)(1).

III. Scoping Methodology

The scoping evaluations for the Indian Point LRA were performed by the applicant's license renewal project personnel. The audit team conducted detailed discussions with the applicant's license renewal project management personnel and reviewed documentation pertinent to the scoping process. The audit team assessed whether the scoping methodology outlined in the LRA and implementation procedures were appropriately implemented and if the scoping results were consistent with current licensing basis requirements. The audit team also reviewed a sample of system scoping results for the following systems and structures: (1) service water system and (2) the turbine building (structural review). The audit team determined that the applicant's scoping methodology was generally consistent with the requirements of the Rule for the identification of SSCs that meet the scoping criteria of 10 CFR 54.4(a). However, the audit team determined that additional information was required in order for the staff to complete its review:

- The applicant had included fluid-filled, nonsafety-related pipes located within a safety-related space within the scope of license renewal based on the spaces approach and had separately addressed nonsafety-related piping attached to safety-related SSCs. The staff requested that the applicant provide a description of the process used to ensure that fluid filled nonsafety-related pipe, attached to safety-related SSCs which exit the safety-related space, was included within the scope of license renewal up to and including an appropriate seismic anchor, equivalent anchor or bounding condition, to the extent necessary to allow the staff to complete its safety review.

- During the NRC audit, the audit team reviewed the applicant's technical evaluation and on-site documentation for nonsafety-related SSCs affecting safety-related SSCs. This technical evaluation indicated that certain nonsafety-related SSCs affecting safety-related SSCs were not included within the scope of license renewal based on the proximity of the nonsafety-related SSCs to the safety-related SSCs. The staff requested that the applicant provide the rational and basis for not including nonsafety-related SSCs in the vicinity of safety-related SSCs within the scope of license renewal based on their proximity to safety-related SSCs.

- During the NRC audit, the audit team reviewed the applicant's technical evaluation and on-site documentation for nonsafety-related affecting safety-related SSCs which indicated that certain similar SSCs were included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1) for one unit and 10 CFR 54.4(a)(2) for the other unit. The staff requested that the applicant provide the rational and basis for including similar SSCs within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1) for one unit and 10 CFR 54.4(a)(2) for the other unit.

IV. Screening Methodology

The audit team reviewed the methodology used by the applicant to determine if mechanical, structural, and electrical components within the scope of license renewal would be subject to further aging management review. The applicant provided the audit team with a detailed discussion of the processes used for each discipline and provided administrative documentation that described the screening methodology. The audit team also reviewed the screening results reports for the service water system and the turbine building. The audit team noted that the applicant's screening process was performed in accordance with its written requirements and was consistent with the guidance provided in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Revision 1, (SRP-LR), and the Nuclear Energy Institute (NEI) 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 6, (NEI 95-10). The audit team determined that the screening methodology was consistent with the requirements of the Rule for the identification of SSCs that meet the screening criteria of 10 CFR 54.21(a)(1).

V. Aging Management Program Quality Assurance Attributes

The audit team reviewed the applicant's aging management programs (AMPs) described in Appendix A, "Updated Final Safety Report Analysis Supplement," and Appendix B, "Aging Management Programs and Activities," of the Indian Point LRA for inclusion of the appropriate quality assurance requirements for elements No. 7 (corrective action), No. 8 (confirmation process) and No. 9 (administrative controls).

In addition, the audit team reviewed each individual AMP basis document to ensure consistency in the use of the quality assurance attributes for each program. The purpose of this review was to assure that the aging management activities were consistent with the staff's guidance described in NUREG-1800, Section A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1).”

Based on the audit team’s evaluation, the descriptions and applicability of the plant-specific aging management programs (AMPs) and their associated quality attributes provided in Appendix A, Sections A.2.1 and A.3.1, and Appendix B, Section B.0.3, of the LRA were determined to be generally consistent with the staff’s position regarding quality assurance for aging management.

VI. Quality Assurance Controls Applied to LRA Development

The audit team reviewed the quality controls used by the applicant to ensure that scoping and screening methodologies used in the LRA were adequately implemented. Although the applicant did not develop the LRA under a 10 CFR 50, Appendix B, QA program, the applicant applied the following quality assurance (QA) processes during the LRA development:

- The applicant developed written plans and procedures to direct implementation of the scoping and screening methodology, control LRA development, and describe training requirements and documentation.

- The applicant considered pertinent issues in previous license renewal applications and corresponding requests for additional information to determine the applicability to Indian Point application.

- The LRA was reviewed by industry peers and the site review committee prior to submittal to the NRC.

The audit team determined that, based on the review of reports and LRA development guidance, and a discussion with the applicant’s license renewal personnel, the quality assurance activities met current regulatory requirements and provided additional assurance that LRA development activities were performed consistently with the applicant’s LRA program requirements.

VII. Training for License Renewal Project Personnel

The audit team reviewed the applicant’s training process for consistent and appropriate guidelines and methodology for the scoping and screening activities. As outlined in the project plan, the applicant required training and documentation for all personnel participating in the LRA development. Personnel were required to complete the training prior to preparing and approving implementation procedures. Training materials included the applicant’s project guidelines; pertinent industry documents; 10 CFR Part 54 and its statement of considerations; NEI 95-10, Revision 6; Regulatory Guide 1.188, “Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses,” Revision 1; SRP-LR; NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Revision 1; and attending an orientation session on license renewal.

The applicant’s procedures specify two levels of training: (1) training for the corporate project team personnel and (2) training for site personnel. Generally the project team personnel reviewed all of the training documents in order to thoroughly comprehend those documents directly related to their specific scoping and screening responsibilities. Training for the site personnel was performed to ensure an understanding of the license renewal process and of materials specifically related to each individual's license renewal responsibilities. Completion of the training allowed site personnel to evaluate and approve the license renewal documents for technical accuracy. Qualification and training records and a check list served as documentation for each individual's completed license renewal training. The audit team reviewed completed qualification and training records and completed check lists for several of the applicant's license renewal personnel.

On the basis of discussions with the applicant's license renewal personnel responsible for the scoping and screening process, and a review of selected documentation in support of the process, the audit team determined that the applicant's personnel understood the requirements and adequately implemented the scoping and screening methodology established in the applicant's renewal application.

VIII. Final Briefing

A final briefing was held with the applicant on October 12, 2007, to discuss the results of the scoping and screening methodology audit. The audit team identified preliminary areas where additional information would be required to support completion of the staff's LRA review.

IX. Documents Reviewed

1. NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Revision 1

2. NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 6

3. IP-RPT-05-LRP01, "License Renewal Project Plan"

4. IPEC-LRPG-03, "System and Structure Scoping"

5. IPEC-LRPG-04, "Mechanical System Screening and Aging Management Review"

6. IPEC-LRPG-05, "Electrical System Screening and Aging Management Review"

7. IPEC-LRPG-04, "Structural Screening and Aging Management Review"

8. IPEC-LRPG-06, "Structural Scoping and Screening and Aging Management Reviews"

9. IP-RPT-06-LRD01, "System & Structure Scoping Results"

10. ENN-MS-S-009-IP2, "IP1/IP2 System Safety Function Sheets"

11. ENN-MS-009-IP3, "IP3 System Safety Function Sheets"

12. IP-RPT-005-00071, "IP2 10 CFR 50, Appendix R Safe-Shutdown Separation Analysis"

13. IP-RPT-06-AMC01, "Aging Management Review of the Containment Buildings"

14. IP-RPT-06-AMC02, "Aging Management Review of the Water Control Structures"

15. IP-RPT-06-AMC03, "Aging Management Review of the Turbine Buildings, Auxiliary Buildings, and Other Structures"

16. IP-RPT-06-AMC04, "Aging Management Review of Bulk Commodities"

17. AMM-30, "Nonsafety Affecting Safety"

X. Personnel Contacted During Methodology Audit

1. Robert Walpole, Entergy Nuclear Operations, Inc., (Entergy), Manager Licensing

2. Gary Young, Entergy, Manager, License Renewal

3. Patric Conroy, Entergy – Director NSA

4. Mike Stroud, Entergy, Project Manager

5. Ted Ivy, Entergy- License Renewal

6. Tom McCaffrey, Entergy – Design Engineering

7. Don Mayer, Entergy – Director VI

8. Charlie Caputo, Entergy – License Renewal Team

9. Bill Josego, Entergy – License Renewal Team

10. Reza Ahrable, Entergy – License Renewal Team

11. Roger Rucker, Entergy – License Renewal Team

12. Brian Adkison, Entergy – License Renewal Team

13. Jill Brochu, Entergy – License Renewal Team

14. David Lach, Entergy – License Renewal Team

15. Jacque Lingenfelter, Entergy – License Renewal Team

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Audit Report for Plant Aging Management Programs and Reviews

Indian Point Nuclear Generating Unit Nos. 2 and 3

Docket No.: 50-247
50-286

Table of Contents

Audit Report for Plant Aging Management Programs and Reviews
For Indian Point Nuclear Generating Units Nos. 2 and 3

1 INTRODUCTION AND GENERAL INFORMATION

1.1 Introduction

By letter dated April 23, 2007, Entergy Nuclear Operations Inc., submitted to the U.S. Nuclear Regulatory Commission (NRC) its application for renewal of Operating License Nos. DPR-26 and DPR-64, for the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3), respectively. The applicant requested renewal of the operating licenses for an additional 20 years beyond the 40-year current license term.

In support of the staff's safety review of the license renewal application (LRA) for IP2 and IP3, the Division of License Renewal (DLR), Engineering Review Branch (RER), led a project team that audited and reviewed selected aging management reviews (AMRs) and associated aging management programs (AMPs), and time-limited aging analyses (TLAAs) developed by the applicant to support its LRA for IP2 and IP3. The project team included NRC staff and engineers provided by Brookhaven National Laboratory (BNL), the RER technical contractor. Appendix A lists the project team members, project team support, and applicant personnel that participated in the audit and review.

The project team performed its work in accordance with the requirements of Title 10 of the *Code of Federal Regulations*, Part 54 (10 CFR Part 54), Requirements for Renewal of Operating Licenses for Nuclear Power Plants; the guidance provided in Revision 1 of NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR); and the guidance provided in Revision 1 of NUREG-1801, Generic Aging Lessons Learned (GALL) Report.

The approach followed by the project team in implementing these requirements and guidance may be found in "Audit and Review Plan for Plant Aging Management Reviews and Programs – Indian Point Generating Units Nos. 2 and 3," Docket Nos. 50-247 and 50-286 (ADAMS Accession No. ML072290180).

This audit report documents the results of the project team's audit work. The project team performed its work at NRC Headquarters, Rockville, Maryland; at the BNL office in Long Island, New York; and at the IP2 and IP3 site in Buchanan, New York. The project team conducted onsite visits during the weeks of August 27 - 31, 2007, October 22 - 26, 2007, November 27 - 29, 2007, and February 19 - 21, 2008.

During the course of the audits, the staff presented numerous questions to the applicant. The staff's questions and the applicant's responses may be found in letters from Entergy to the NRC dated December 18, 2007 (ADAMS Accession No. ML073650195) and March 24, 2008 (ADAMS Accession No. ML081070255). To the extent that the questions relate to the consistency of the applicant's AMP with the GALL Report, they are documented in this report.

In other respects, the questions will be addressed in the staff's safety evaluation report (SER) related to the IP2 and IP3 LRA.

1.2 Background

In 10 CFR 54.4, the scope of license renewal is defined as those systems, structures, and components (SSCs) (1) that are safety-related, (2) that are nonsafety-related but whose failure could prevent satisfactory performance of safety-related functions, or (3) that are relied on to demonstrate compliance with NRC regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and station blackout. An applicant for a renewed license must review all SSCs within the scope of license renewal to identify those structures and components (SCs) subject to an AMR pursuant to 10 CFR 54.21(a)(1). Structures and components subject to an AMR are those that perform an intended function without moving parts or without a change in configuration or properties, and that are not subject to replacement based on qualified life or specified time period. Pursuant to 10 CFR 54.21(a)(3), an applicant for a renewed license must demonstrate that the effects of aging will be adequately managed so that the intended function or functions of those SCs will be maintained consistent with the current licensing basis (CLB) for the period of extended operation.

License renewal also requires the identification of TLAAs. During the design phase for a plant, certain assumptions are made about the length of time the plant would operate. These assumptions are incorporated into design calculations for several of the plant's SSCs. In accordance with 10 CFR 54.21(c)(1), the applicant for a renewed license must either show that these calculations remain valid for the period of extended operation, project the analyses to the end of the period of extended operation, or demonstrate that the effects of aging on the intended function(s) of these SSCs will be adequately managed for the period of extended operation.

In addition, 10 CFR 54.21(d) requires that the applicant submit a supplement to the Final Safety Analysis Report (FSAR) that contains a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation.

The SRP-LR provides staff guidance for reviewing applications for license renewal. The GALL Report is a technical basis document. It provides staff-approved AMPs for managing aging of a large number of SCs that are subject to an AMR. It also summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the SCs used by commercial nuclear power plants, and serves as a reference for both the applicant and staff reviewers to quickly identify those AMPs and activities that the staff has determined will provide adequate aging management during the period of extended operation. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources used to review an applicant's LRA will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report identifies (1) SSCs, (2) component materials, (3) environments to which the components are exposed, (4) aging effects/aging mechanisms associated with the materials and environments, (5) AMPs that are credited with managing the aging effects, and (6) recommendations for further applicant evaluations of aging effects and their management for certain component types.

The GALL Report is treated in the same manner as an NRC-approved topical report that is generically applicable. An applicant may reference the GALL Report in its LRA to demonstrate that its programs correspond to those that the staff reviewed and approved in the GALL Report. If the material presented in the LRA is consistent with the GALL Report and is applicable to the applicant's facility, the staff will accept the applicant's reference to the GALL Report. In making this determination, the staff considers whether the applicant has identified specific programs described and evaluated in the GALL Report, but does not conduct a review of the substance of the matters described in the GALL Report. Rather, the staff determines whether the applicant established that the approvals set forth in the GALL Report apply to its programs.

If an applicant takes credit for a GALL Report program, it is incumbent on the applicant to ensure that its plant program addresses all ten program elements of the referenced GALL Report program. These elements are described in SRP-LR, Appendix A.1, "Aging Management Review – Generic (Branch Technical Position RLSB-1)." In addition, the conditions at the plant must be bounded by the conditions for which the GALL Report program was evaluated. The applicant must certify in its LRA that it completed the appropriate verifications and that those verifications are documented and retained by the applicant in an auditable form.

The SRP-LR also provides staff guidance for reviewing TLAAs. Pursuant to 10 CFR 54.21(c)(1), the applicant is required, in its LRA, to provide a list of TLAAs, as defined in 10 CFR 54.3. In addition, the applicant must provide a list of plant-specific exemptions granted under 10 CFR 50.12 that are based on TLAAs. The number and type of TLAAs vary, depending on the plant-specific current licensing basis (CLB). All six criteria set forth in 10 CFR 54.3 must be satisfied to conclude that a calculation or analysis is a TLAA. The applicant must demonstrate that the TLAAs remain valid for the period of extended operation; the TLAAs have been projected to the end of the period of extended operation; or the aging effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The project team performs technical reviews, as well as reviews the area relating to the identification of TLAAs. The project team also determines whether the applicant omitted any TLAAs, as defined in 10 CFR 54.3.

2 AUDIT SCOPE

The purpose of the audit was to review the applicant's AMPs, AMRs, and TLAAs against the requirements of 10 Part 54, the guidance provided in the SRP-LR and the GALL Report to verify that the applicant's aging management activities and programs will adequately manage the effects of aging on structures and components, so that their intended functions will be maintained consistent with the IP2 and IP3 current licensing basis (CLB) for the period of extended operation.

The audit for IP2 and IP3 was intended to accomplish the following:

- For IP2 and IP3 AMPs that the applicant claimed are consistent with the GALL Report AMPs, verify that the plant AMPs contain the program elements of the referenced GALL Report AMPs and that the conditions at the plant are bounded by the conditions for which the GALL Report AMPs were evaluated.

- For IP2 and IP3 AMPs that the applicant claimed are consistent with the GALL Report AMPs with exceptions, verify that the plant AMPs contain the program elements of the referenced GALL Report AMPs and that the conditions at the plant are bounded by the conditions for which the GALL Report AMPs were evaluated. In addition, verify that the applicant has documented an acceptable technical basis for each exception.

- For IP2 and IP3 AMPs that the applicant claimed will be consistent with the GALL Report AMPs after specified enhancements are implemented, verify that the plant AMPs, with the enhancements, will be consistent with the referenced GALL Report AMPs, or are acceptable on the basis of a technical review. In addition, verify that the applicant identified the enhancements as commitments in the Updated Final Safety Analysis Report (UFSAR) or other docketed correspondence.

- For IP2 and IP3 AMPs that the applicant claimed are consistent with or will be consistent with exceptions and/or enhancements to the GALL Report AMPs, review the operating experience reports, including a sample of condition reports, and confirm that the operating experience does not reveal any degradation not bounded by industry experience.

- For AMR line items that the applicant claimed are consistent with the GALL Report, verify that these AMR line items are consistent with the recommendation of the GALL Report.

- For metal fatigue TLAAs, verify that the applicant has properly identified the TLAAs. In addition, review documentation to verify that the applicant has demonstrated that (1) the TLAAs remain valid for the period of extended operation; (2) the TLAAs have been projected to the end of the period of extended operation; or (3) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

This audit report documents the staff's verification of the applicant's claims of consistency with the GALL Report AMPs and AMRs. This report also documents the staff's verification of documentation in support of metal fatigue TLAAs. Time limited aging analyses for matters other than metal fatigue will be reviewed in the staff's Safety Evaluation Report (SER) for the IP2 and IP3 LRA. The staff's evaluation of the AMPs, AMRs and TLAAs will be documented in the staff's SER for the IP2 and IP3 LRA.

3 AGING MANAGEMENT PROGRAMS

This section of the audit report contains the project team's verification of the AMPs that the applicant claimed to be consistent with the GALL Report for IP2 and IP3. In Appendix B of the IP2 and IP3 LRA, the applicant described the AMPs that it relies on to manage or monitor the aging of long-lived, passive components and structures. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that program elements (1) "scope of program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," and (6) "acceptance criteria," are consistent with the corresponding elements in the

GALL AMP. In addition, the staff asked questions to obtain clarification and/or additional details about certain aspects of the AMP. By letters dated December 18, 2007, and March 24, 2008, the applicant provided responses, under oath or affirmation, to the staff's questions.

The staff's evaluation of the "operating experience" element will be documented in the staff's SER for the Indian Point LRA.

The staff's evaluation of the Quality Assurance program includes assessment of program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls." Unless otherwise noted, the staff's review of these elements, as part of the applicant's Quality Assurance program will be documented in SER Section 3.0.4.

3.1 Aging Management Programs that are Consistent with GALL

3.1.1 LRA AMP B.1.5, "Boric Acid Corrosion Prevention"

In the LRA, the applicant stated that the Boric Acid Corrosion Prevention Program is an existing program that is consistent with GALL AMP XI.M10, "Boric Acid Corrosion."

During the audits, the staff verified that elements (1) through (6) of the Boric Acid Corrosion Prevention Program are consistent with the corresponding elements of the XI.M10 AMP in the GALL Report. In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document Number	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.4	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Boric Acid Corrosion Prevention	Rev. 2
NUREG-1801, XI.M10	Boric Acid Corrosion	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 1
ENN-DC-319	Inspection and Evaluation of Boric Acid Leaks	Rev. 0
EN-DC-178	System Walkdown	Rev. 1
2-PT-R156	[Reactor Coolant System (RCS)] RCS Boric Acid Leakage and Corrosion Inspection	Rev. 0
3-PT-114	RCS Boric Acid Leakage and Corrosion Inspection	Rev. 9
3-PT-114A	Reactor Vessel and Closure Head Boric Acid Leakage and Corrosion Inspection	Rev. 0

In comparing the elements in the applicant's AMP with GALL AMP XI.M10, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

Audit Item 24:

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 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

Applicant's Response (Audit Item 24):

[Indian Point Energy Center (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 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-R1 56, "RCS Boric Acid Leakage and Corrosion Inspection", 3-PT-R114A, "Reactor Vessel and Closure Head Boric Acid Leakage and Corrosion Inspection", and 3-PT-R1 14, "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-PTR204, "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 [sic] 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 [sic] 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"

<u>Audit Item 109</u>:

Have you observed boric acid leakage from the Conoseal flanges?

Applicant's Response (Audit Item 109):

> 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.

Staff's Findings

Based on its audit of the applicant's onsite documents and review of the applicant's responses to the staff's questions, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.2 LRA AMP B.1.6, "Buried Piping and Tanks Inspection"

In the LRA, the applicant stated that the Buried Piping and Tanks Inspection Program is a new program that will be consistent with GALL AMP XI.M34, "Buried Piping and Tanks Inspection."

During the audits, the staff verified that elements (1) through (6) of the Buried Piping and Tanks Inspection Program are consistent with the corresponding elements of the XI.M34 AMP in the GALL Report. At the time of the audits, the applicant had not yet developed procedures for this new program; and the staff's audit addressed only the applicant's program elements and the corresponding program in the GALL Report. The applicant has committed to implement the program consistent with the GALL Report prior to the period of extended operation. In accordance with Inspection Procedure (IP) 71003, the staff will verify that the license renewal commitments are implemented in accordance with 10 CFR Part 54.

In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 3.1	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Buried Piping and Tanks Inspection Program	Rev. 2
NUREG-1801, XI.M34	Buried Piping and Tanks Inspection	Rev. 1

In comparing the elements in the applicant's AMP with GALL AMP XI.M34, the staff identified an area in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's request and the applicant's response are provided below.

Audit Item 110:

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?

Applicant's Response (Audit Item 110):

> The following tanks are buried and in scope for license renewal and included in the Buried Piping and Tanks Inspection Program.
>
> IP2 Fuel Oil Storage Tanks (21/22/23 FOST)
> GT1 Fuel Oil Storage North and South Storage Tanks
> IP2 Security Diesel Fuel Tank
> IP3 Appendix R Fuel Oil Storage Tank (EDG-33-FO-STNK)
> IP3 Security Propane Fuel Tanks (2 of them)
> IP3 Fuel Oil Storage tanks (EDG-31/32/33-FO-STNK)
>
> A review of site condition reports back to 2000 revealed that there have been two underground piping leaks that occurred on the auxiliary steam supply cross connect line between Unit 2 and Unit 3. The first leak occurred in 2002 and CR-IP3-2002-04267 was written for this leak. The leak was repaired via the work control process. The second leak occurred in April 2007 and is documented in CR-IP3-2007-01852. This line has been excavated and replaced. The cause of the failure was determined to be advanced corrosion of the pipe due to moisture intrusion. This was caused by the pipe coating breaking down and insulation that was not sufficient for the task. After replacement, the pipe was reinsulated using a special high temperature application moisture resistant material that was designed to prevent this type of corrosion in the future. This piping is nonsafety-related and not in the scope of license renewal. Copies of the condition reports were provided. No other buried piping repair or replacement was identified during review of operating experience.

Staff's Findings

Based on its audit of the applicant's onsite documents and review of the applicant's responses to the staff's questions, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.3 LRA AMP B.1.7, "Containment Leak Rate"

In the LRA, the applicant stated that the Containment Leak Rate Program is an existing program that is consistent with GALL AMP XI.S4, "10 CFR Part 50, Appendix J."

During the audits, the staff verified that elements (1) through (6) of the Containment Leak Rate Program are consistent with the corresponding elements of the XI.S4 AMP in the GALL Report. In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document Number	Title	Revision or Date
IP-RPT-06-LRD08, Sec. 3.1	Aging Management Program Evaluation Report Structural/Civil, Containment Leak Rate Program	Rev. 2
NUREG-1801, XI.S4	10 CFR Part 50, Appendix J	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 0
ENN-DC-334	Primary Containment Leakage Rate Testing (Appendix J), Entergy Nuclear Northeast Nuclear Management Manual	Rev. 0
PFM-109	Containment Leakage Rate Testing Program	Rev. 6

In comparing the elements in the applicant's AMP with GALL AMP XI.S4, the staff identified an area in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's request and the applicant's response are provided below.

<u>Audit Item 25</u>:

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 [leak rate test] programs for systems containing the isolation valves." Is Entergy crediting 10 CFR Part 50, Appendix J, Type C containment isolation valve leak rate testing during the license renewal period?

<u>Applicant's Response (Audit Item 25)</u>:

> 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.

<u>Staff's Findings</u>

The applicant's program description indicated that the Containment Leak Rate Program is an existing program conducted in accordance with 10 CFR Part 50, Appendix J. The applicant also stated that the IP2 and IP3 programs comply with 10 CFR 50, Appendix J, Option B, the guidance in Regulatory Guide (RG) 1.163, and the recommendations in Nuclear Energy Institute (NEI) 94-01. The staff finds the applicant's statement acceptable because it is consistent with the GALL Report program description. The staff also reviewed the applicant's program basis document and confirmed that the Containment Leak Rate Program at IP2 and IP3 is an existing program that is in compliance with 10 CFR Part 50, Appendix J.

The program basis document refers to the applicant's Primary Containment Leakage Rate Testing (Appendix J) Program and the site-specific Containment Leakage Rate Testing Program for IP2/IP3 units for additional information. The Appendices to the Containment Leakage Rate Testing Program specifically list the penetrations and valves which are tested to meet the requirements of 10 CFR Part 50, Appendix J. The staff finds that the scope of the applicant's Containment Leakage Rate Testing Program is consistent with the GALL Report program element.

The Containment Leak Rate Program does not include preventive actions. It is a testing program; and, therefore, is consistent with the GALL Report.

The program basis documents identify that this AMP monitors the leakage rates through the containment shell; containment liner; and associated welds, fittings, and other access openings. The program basis document refers to the applicant's Primary Containment Leakage Rate Testing (Appendix J) Program, Sections 3.0 (Items 40, 41, 42), 5.4, and 5.5, and the IP2 and IP3 site-specific Containment Leakage Rate Testing Program, Appendices B, C, and D. These sections describe in greater detail the requirements which the applicant must meet when measuring the leakage rates of the overall primary containment, penetrations, and isolation valves. The staff finds that the parameters monitored and/or inspected by the applicant are consistent with the GALL Report.

The GALL Report states that a Containment Leak Rate program, conducted in accordance with 10 CFR Part 50, Appendix J, is not sufficient for detecting aging effects. Containment leakage may be caused by aging degradation, and aging degradation in an advanced stage may be undetected under this program. However, the applicant relies upon the American Society of Mechanical Engineers (ASME) Code Section XI, Subsections IWE and IWL containment inspection programs to detect aging degradation, well before leakage occurs. In this respect, the applicant's program is consistent with the GALL Report.

The AMP program description in the LRA states that the applicant's program meets the requirements of 10 CFR Part 50, Appendix J, Option B; follows the guidance of RG 1.163; and follows the recommendations of NEI 94-01. The staff's review of the program basis documents confirmed that this AMP monitors the leakage rates pursuant to 10 CFR Part 50, Appendix J, Option B; RG 1.163; and NEI 94-01. In order to be considered for extended test intervals, the applicant's Primary Containment Leakage Rate Testing (Appendix J) Program, Section 5.2, and the IP2 and IP3 site-specific Containment Leakage Rate Testing Program, Appendix A, describe the requirements for repeated leakage rate tests, whose test intervals are based on the performance in prior tests. Since the leakage rates through the containment are trended over time, in accordance with 10 CFR Part 50, Appendix J, Option B; RG 1.163; and NEI 94-01, the staff finds that the applicant's monitoring and trending is consistent with the GALL Report.

The program basis documents indicate that the IP2 and IP3 acceptance criteria are defined in plant technical specifications. Technical Specification (TS), Sections 5.5.14 and 5.5.15 for IP2 and IP3 are referenced. The technical specifications are part of the current licensing basis of the plant. TS Sections 5.4 and 5.5 of the applicant's Primary Containment Leakage Rate Testing (Appendix J) program summarize the applicant's acceptance criteria for the Type A tests and Type B/C tests, and Appendix A of the site-specific Containment Leakage Rate Testing Program for IP2 and IP3 provides a list of the specific technical specification requirements applicable to IP2 and IP3. The staff finds that the acceptance criteria are consistent with the GALL Report program element.

Based on its audit of the applicant's onsite documents and review of the applicant's responses to the staff's questions, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.4 LRA AMP B.1.10, "Environmental Qualification (EQ) of Electric Components"

LRA Section AMP B.1.10 stated that the Environmental Qualification (EQ) of Electric Components Program is an existing program that is consistent with GALL AMP XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

During the audits, the staff verified that elements (1) through (6) of the Environmental Qualification (EQ) of Electric Components Program are consistent with the corresponding elements of the XI.E1 AMP in the GALL Report. In additon, the staff interviewed the applicant's technical staff and reviewed the following onsite documents.

Document	Title	Revision or Date
IP-RPT-06-LRD09, Sec. 4.1	Aging Management Program Evaluation Report -Electrical, Environmental Qualification (EQ) of Electric Components Program	Rev. 2
NUREG-1801, XI.E1	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 0
ENN-DC-164	Environmental Qualification (EQ) Program, Entergy Nuclear Northeast Nuclear Management Manual	Rev. 2

In comparing the elements in the applicant's AMP with GALL X.E1, the staff identified an area in which additional information or clarification was needed. During the discussion of the EQ program with the applicant, the process of incorporating plant specific operating experience (OE) in the program OE was discussed. The staff requested the applicant provide OE, in addition to that included in the LRA, associated with the EQ program. In a letter March 24, 2008, the applicant provided the requested information. The staff's evaluation of the applicant's response will be provided in the staff's SER Section 3.0.3.1.4.

Staff's Findings

Based on its audit of the applicant's onsite documents, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.5 LRA AMP B.1.15, "Flow-Accelerated Corrosion"

In the LRA, the applicant stated that the Flow-Accelerated Corrosion (FAC) Program is an existing program that is consistent with GALL AMP XI.M17, "Flow-Accelerated Corrosion."

During the audits, the staff verified that elements (1) through (6) of the Flow-Accelerated Corrosion (FAC) Program are consistent with the corresponding elements of the XI.M17 AMP in the GALL Report. In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.9	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Flow-Accelerated Corrosion Program	Rev. 2
NUREG-1801, XI.M17	Flow-Accelerated Corrosion	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 1
EN-DC-315	Flow Accelerated Corrosion Program	Rev. 0
ENN-CS-S-008	Pipe Wall Thinning Structural Evaluation	Rev. 1
ENN-NDE-9.05	Ultrasonic Thickness Examination	Rev. 1
050714b-01	IP2 CHECWORKS FAC Model (on disk only, 216 pages)	Rev. 1
IP-RPT-05-00407	IPEC Snapshot Self-Assessment Report for condition report LO-IP3LO-2005-0328	Rev. 0
94-10.1-05	CHECWORKS Global Input	Rev. 2
QA-08-2004-IP-1	Audit Report 2004	

In comparing the elements in the applicant's AMP with GALL AMP XI.M17, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

<u>Audit Item 43</u>:

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.

<u>Applicant's Response (Audit Item 43)</u>:

> 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 3R1 3 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

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"

Audit Item 44:

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?

Applicant's Response (Audit Item 44):

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.

Audit Item 45:

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?

Applicant's Response (Audit Item 45):

1. Update of CHECWORKS version from 1.OG 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. 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.

Audit Item 46:

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.

Applicant's Response (Audit Item 46):

[1] If a component is discovered that has a current or projected wall thickness less than the minimum acceptable wall thickness (T_{accpt}), then additional inspections of identical or similar piping components in a parallel or alternate train is performed to bound the extent of thinning.

[2] When inspections of components detect significant wall thinning, the sample size for that line is increased to include the following:

(a) Components within two diameters downstream of the component displaying significant wear or within two diameters upstream if the component is an expander or expanding elbow.

(b) A minimum of the next two most susceptible components from the relative wear ranking in the same train as the piping component displaying significant wall thinning.

(c) Corresponding components in each other train of a multi-train line with a configuration similar to that of the piping component displaying significant wall thinning.

Vent Chamber Drain (VCD) pipe thinning during 3R13:

3R13 inspection of a VCD elbow immediately downstream of MSR-31A PCV-7008 found wall thinning less than the minimum acceptable wall thickness, requiring replacement of the elbow. Based on the results of this exam, a sample expansion was performed to determine the extent of condition for this pipe thinning.

The expansion included corresponding components on the other moisture separator reheaters with a configuration similar to that of the elbow displaying the thinning. Four additional inspections were performed. These inspections also found wall thinning less than the minimum acceptable wall thickness, requiring replacement of these components.

The sample expansion was continued until no additional components were detected with significant wear. Four additional inspections were performed downstream of the worn elbows. The results of this expansion did not find significant wear and the sample expansion was terminated.

The vent chamber drain lines on Unit 2 were replaced with FAC-resistant materials, and were not considered in this sample expansion.

Reheater Drain pipe thinning during 3R14:

A leak in the reheater drain system was detected during cycle 14. A review of both Unit 2 and Unit 3 FAC programs was performed to determine if similar locations to this leak have been inspected for wall thinning and determine if additional inspections were required.

A review of the Unit 2 FAC inspection history found that all similar locations had been recently inspected or replaced. No additional inspections were recommended. 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.

<u>Audit Item 47</u>:

How is the industry experience utilized in the FAC Program at Indian Point? How does IP get 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?

Applicant's Response (Audit Item 47):

> 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.

Audit Item 48:

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, 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?

Applicant's Response (Audit Item 48):

(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-08-2007-1P-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-1 344, 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 Revision 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.

Audit Item 49:

The LRA includes operating experience items which pertain to inspections during 3R13 and 2R17 outages for IP3 and IP2 respectively. Both items are recent (March 2005 and May 2006 respectively) items. Provide more examples of inspection results to demonstrate that the FAC program at Indian Point is effective in managing the aging effect.

Applicant's Response (Audit Item 49):

Identification of degradation and corrective action prior to loss of intended function provide assurance that the FAC Program is effective for managing aging effects due to flow accelerated corrosion. Corrective actions are addressed by the wet steam replacement project. This project is a multi-year task to replace FAC susceptible piping with FAC resistant material. Replacement materials include stainless steel, chrome-moly and carbon steel pipe with a stainless steel liner.

The following are more examples of inspection results to demonstrate that the FAC 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 3R1 5. 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 3R1 2 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-1 105A 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.

Audit Item 156:

The program description provided for AMP B.1.15 in the LRA states that the program is based on the guidelines of EPRI NSAC-202LR2. The review of Indian Point Procedure EN-DC-315, Rev. 0 Flow Accelerated Corrosion Program provided during the site audit, references "latest" revision of this document which is revision 3. Since the guidelines provided in two revisions of NSAC-202L are different, address which revision 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.

Applicant's Response (Audit Item 156):

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

Staff's Findings

Based on its audit of the applicant's onsite documents and review of the applicant's responses to the staff's questions, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.6 LRA AMP B.1.23, "Non-EQ Inaccessible Medium-Voltage Cable"

LRA Section AMP B.1.23 stated that the Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that will be consistent with GALL AMP XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

During the audits, the staff verified that elements (1) through (6) of the Non-EQ Inaccessible Medium-Voltage Cable Program are consistent with the corresponding elements of the XI.E3 AMP in the GALL Report. At the time of the audits, the applicant had not yet developed procedures for this new program; and the staff's audit addressed only the applicant's program elements and the corresponding program in the GALL Report. The applicant has committed to implement the program consistent with the GALL Report prior to the period of extended operation. In accordance with IP 71003, the staff will verify that the license renewal commitments are implemented in accordance with 10 CFR Part 54.

In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD09, Sec. 3.2	Aging Management Program Evaluation Report - Electrical, Non-EQ Inaccessible Medium-Voltage Cable Program	Rev. 2
NUREG-1801, XI.E3	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Rev. 1

In comparing the elements in the applicant's AMP with GALL AMP XI.E3, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

Audit Item 123:

Why are cables for service water pump motors not included in the B.1.23 AMP?

Applicant's Response (Audit Item 123):

> 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)

Audit Item 159:

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 performed to determine the proper frequency for manhole inspection. Provide information for how this will use OE to justify the frequency.

Applicant's Response (Audit Item 159):

LRA Section B.1.23 and the site AMP evaluation document state that 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 example 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 inspections 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.

Staff's Findings

Based on its audit of the applicant's onsite documents and review of the applicant's responses to the staff's questions, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.7 LRA AMP B.1.24, "Non-EQ Instrumentation Circuits Test Review"

LRA Section AMP B.1.24 stated that the Non-EQ Instrumentation Circuits Test Review Program is a new program that will be consistent with GALL AMP XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits."

During the audits, the staff verified that elements (1) through (6) of the Non-EQ Instrumentation Circuits Test Review Program are consistent with the corresponding elements of the XI.E2 AMP in the GALL Report. At the time of the audits, the applicant had not yet developed procedures for this new program; and the staff's audit addressed only the applicant's program elements and the corresponding program in the GALL Report. The applicant has committed to implement the program consistent with the GALL Report prior to the period of extended operation. In accordance with IP 71003, the staff will verify that the license renewal commitments are implemented in accordance with 10 CFR Part 54.

In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD09, Sec. 3.3	Aging Management Program Evaluation Report– Electrical, Non-EQ Instrumentation Circuits Test Review Program	Rev. 2
NUREG-1801, XI.E2	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Rev. 1
SAND96-0344, Specified Dissemination UC-523	Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations, September 1996	

In comparing the elements in the applicant's AMP with GALL AMP XI.E2, the staff identified an area in which additional information or clarification was needed.

GALL AMP XI.E2 states that this program applies to high-range-radiation monitor and neutron flux monitoring instrumentation cables in addition to other cables used in high voltage, low level signal applications that are sensitive to reduction insulation resistance (IR). In the Non-EQ Instrumentation Circuits Test Review Program, the applicant only discussed neutron monitoring system cables. The staff requested the applicant to explain why high-range radiation monitoring cables were not included in the AMP B.1.24. The staff also requested the applicant to list other cables used in high voltage low level signal application and explain why these cables were not included in the scope of Non-EQ Instrumentation Circuits Test Review Program (Audit Item 64). In a letter dated March 24, 2008, the applicant provided the requested information. The staff's evaluation of the applicant's response will be documented in the staff's SER Section 3.0.3.1.7.

Staff's Findings

Based on its audit of the applicant's onsite documents, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.8 LRA AMP B.1.25, "Non-EQ Insulated Cables and Connections"

LRA Section AMP B.1.25 stated that the Non-EQ Insulated Cables and Connections Program is a new program that will be consistent with GALL AMP XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

During the audits, the staff verified that elements (1) through (6) of the Non-EQ Insulated Cables and Connections Program are consistent with the corresponding elements of the XI.E1 AMP in the GALL Report. At the time of the audits, the applicant had not yet developed procedures for this new program; and the staff's audit addressed only the applicant's program elements and the corresponding program in the GALL Report. The applicant has committed to implement the program consistent with the GALL Report prior to the period of extended operation. In accordance with IP 71003, the staff will verify that the license renewal commitments are implemented in accordance with 10 CFR Part 54.

In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD09, Sec. 3.4	Aging Management Program Evaluation Report–Electrical, Non-EQ Insulated Cables and Connections Program	Rev. 2
NUREG-1801, XI.E1	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Rev. 1

In comparing the elements in the applicant's AMP with GALL AMP XI.E1, the staff identified an area in which additional information or clarification was needed.

GALL XI.E1, under program description, states that this program can be thought of as a sampling program. Selected cables and connection from accessible areas (the inspection sample) are inspected and represent, with reasonable assurance, all cables and connection in the adverse localized environments. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections. In the program description of AMP B.1.25, the applicant stated that a representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected. The staff requested the applicant to provide technical basis for sampling and action taken if degradation was found on a representative sample (Audit Item 65). In a letter dated March 24, 2008, the applicant provided the requested information. The staff's evaluation of the applicant's response will be documented in the staff's SER Section 3.0.3.1.8.

Staff's Findings

Based on its audit of the applicant's onsite documents, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.9 LRA AMP B.1.27, "One-Time Inspection"

In the LRA, the applicant stated that the One-Time Inspection Program is a new program that will be consistent with GALL AMP XI.M32, "One-Time Inspection."

During the audits, the staff verified that elements (1) through (6) of the One-Time Inspection Program are consistent with the corresponding elements of the XI.M32 AMP in the GALL Report. At the time of the audits, the applicant had not yet developed procedures for this new program; and the staff's audit addressed only the applicant's program elements and the corresponding program in the GALL Report. The applicant has committed to implement the program consistent with the GALL Report prior to the period of extended operation. In accordance with IP 71003, the staff will verify that the license renewal commitments are implemented in accordance with 10 CFR Part 54.

In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 3.2	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, One-Time Inspection Program	Rev. 2
NUREG-1801, XI.M32	One-Time Inspection	Rev. 1

In comparing the elements in the applicant's AMP with GALL AMP XI.M32, the staff identified areas in which additional information or clarification was needed. In letters dated December 18, 2007, and March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

Audit Item 70:

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 within the 10 years period prior to the period of extended operation.

Applicant's Response (Audit Item 70):

> 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.

Audit Item 71:

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.

Applicant's Response (Audit Item 71):

> Consistent with NUREG-1801, XI.M32 each inspection activity includes a representative sample of the material and environment population, and, where practical, focuses on the components most susceptible to aging due to time in service and severity of operating conditions. Also, the program provides for increasing the inspection sample size and locations if aging effects are detected.
>
> EPRI Report 107514, Age Related Degradation Inspection Method and Demonstration, describes methods used to inspect for age related degradation during the period of extended operation. As stated in this report, one key feature of applying the 90% confidence level is the assumption that none of the inspected items will contain significant aging effects. Consequently, if a single item in the sample population has an aging mechanism of interest, the sample size is increased which will raise the confidence level to greater than 90%.
>
> With a combination of proven statistical sampling, focus on susceptible locations, and a mechanism for increasing the sample size, the One-Time Inspection

Program provides adequate assurance that the applicable components will continue to perform their intended function through the period of extended operation.

Audit Item 72:

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?

Applicant's Response (Audit Item 72):

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 10 CFR 50, 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 10 CFR 50, 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 10 CFR 50, Appendix B to verify the absence of significant cracking, corrosion or fouling.

Audit Item 171:

Please include a statement about inspection techniques utilized to the description of the One-Time Inspection Program in LRA Section B.1.27.

Applicant's Response (Audit Item 171):

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

Audit Item 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.

Applicant’s Response (Audit Item 172):

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

Audit Item 281:

A certification should be included in the LRA that the following verifications with respect to this aging management program (AMP B.1.27) are documented onsite in an auditable form:

1. The plant aging management program AMP B.1.27, One Time Inspection Program, contains all elements of NUREG-1801, Rev. 1, AMP XIM32

2. The conditions at the plant are bounded by the conditions for which the GALL AMP (XI.M32) was evaluated

Applicant’s Response (Audit Item 281):

1. The AMP B.1.27 One-Time Inspection Program contains all 10 elements of the NUREG-1801 Rev. 1 program XI.M32. This 10 element comparison is available in Report IP-RPT-06-LRD07 in Section 3.2, which is available on site for review.

2. The IPEC One-Time Inspection Program, as well as the XI.M32 program in NUREG-1801, are credited for various materials and environments to confirm the effectiveness of other aging management programs such as Water Chemistry, Diesel Fuel Monitoring and Lube Oil Analysis and to address concerns for potentially long incubation periods for certain aging effects on structures and components. There are cases where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. For these cases, there will be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly such that an ongoing aging management program is not necessary to ensure the component or structure intended function. This is consistent with XI.M32 program description which states:

"Situations in which additional confirmation is appropriate include (a) an aging effect is not expected to occur but the data is insufficient to rule it out with reasonable confidence; (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected; or (c) the characteristics of the aging effect include a long incubation period. For these cases, there is to be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation."

Therefore, the IPEC One-Time Inspection Program addresses the same types of conditions as those for which the XI.M32 program in NUREG-1801 was evaluated.

The comparisons with XI.M32 are available in report IP-RPT-06-LRD07 in Section 3.2, which is available on site for review.

Staff's Findings

Based on its audit of the applicant's onsite documents and review of the applicant's responses to the staff's questions, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.10 LRA AMP B.1.28, "One-Time Inspection – Small Bore Piping"

In the LRA, the applicant stated that the One-Time Inspection – Small Bore Piping Program is a new program that will be consistent with GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping."

During the audits, the staff verified that elements (1) through (6) of the One-Time Inspection – Small Bore Piping Program are consistent with corresponding elements of the XI.M35 AMP in the GALL Report. At the time of the audits, the applicant had not yet developed procedures for this new program; and the staff's audit addressed only the applicant's program elements and the corresponding program in the GALL Report. The applicant has committed to implement the program consistent with the GALL Report prior to the period of extended operation. In accordance with IP 71003, the staff will verify that the license renewal commitments are implemented in accordance with 10 CFR Part 54.

In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD02, Sec. 3.1	Aging Management Program Evaluation Report – Class 1 Mechanical, One-Time Inspection – Small Bore Piping Program	Rev. 2
NUREG-1801,	One-Time Inspection of ASME Code Class 1	Rev. 1

Document	Title	Revision or Date
XI.M35	Small-Bore Piping	

In comparing the elements in the applicant's AMP with GALL AMP XI.M35, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

Audit Item 73:

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.

Applicant's Response (Audit Item 73):

> Inspections performed to date at IP2 and IP3 have not found cracking of ASME Code Class 1 small-bore piping.

Audit Item 74:

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. Inspections performed to date at IP2 and IP3 have not found cracking of ASME Code Class 1 small-bore piping.

(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.

(a) Will this new program to be implemented by Indian Point follow the guidelines of EPRI Report 1000701 for identifying the susceptible locations for inspection?

(b) If Indian Point One-Time Inspection Program will not utilize the guidelines of the above EPRI Report, what criteria will be used for identification of susceptible locations? Also justify that this criteria will be equivalent to the EPRI guidelines.

Applicant's Response (Audit Item 74):

> (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).

Audit Item 174:

The program description provided for AMP B.1.28 in the LRA states that the One-Time Inspection - Small Bore Piping Program is a new program applicable to small bore ASME Code Class 1 piping less than 4 inches nominal pipe size (NPS 4"), which includes pipe, fittings, and branch connections. The LRA also states that the Indian Point's new program will be consistent with NUREG-1801 Program XI.M35, One-Time Inspection of ASME Code Class 1 Small-Bore Piping. However, NUREG-1801, Section XI.M35, states that the program is applicable to small-bore ASME Code Class 1 piping and systems less than or equal to 4 inches nominal pipe size (i.e., sizes up to and including 4 inch size). If Indian Point intends to exclude 4" size from AMP B.1.28, this should be treated as an exception to GALL and a justification included in the LRA to establish consistency with the GALL report.

Applicant's Response (Audit Item 174):

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.

Audit Item 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.

Applicant's Response (Audit Item 283):

> 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 XIM35. 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.

Staff's Findings

Based on its audit of the applicant's onsite documents and review of the applicant's responses to the staff's questions, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.11 LRA AMP B.1.30, "Reactor Head Closure Studs"

In the LRA, the applicant stated that the Reactor Head Closure Studs Program is an existing program that is consistent with GALL AMP XI.M3, "Reactor Head Closure Studs."

During the audits, the staff verified that elements (1) through (6) of the Reactor Head Closure Studs Program are consistent with the corresponding elements of the XI.M3 AMP in the GALL Report. In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD02, Sec. 4.5	Aging Management Program Evaluation Report – Class 1 Mechanical, Reactor Head Closure Studs	Rev. 2
NUREG-1801, XI.M3	Reactor Head Closure Studs	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 1
R-4147-00-1	Reactor Vessel Tensioning Optimization Stress Report Indian Point Units 2 and 3, Rev. 0	
IP2-RPT-03-00006	Third Ten-Year Inspection Interval, Inservice Inspection Program	Rev. 3
2-REF-002-GEN, Sec. 2.9	Reactor Vessel Head Stud Cleaning	Rev. 1
ER04-2-027	Plasma Bonding Reactor Vessel Flange Studs	Rev. 0
2-PT-R075	RCS Integrity Inspection	Rev. 12
IP3-RPT-UNSPEC-03247	Inservice Inspection Program, Third Ten-Year Interval	Rev. 3
3-REF-002-GEN	Reactor Disassembly and Reassembly	Rev. 0

Document	Title	Revision or Date
ER04-3-009	Plasma Bonding Reactor Vessel Flange Studs	Rev. 0
3-PT-R131	RCS Integrity Leak Test	Rev. 11
Customer Order # 47-64-169	Certificate of Test: Original Studs IP2, June 9, 1967	
Purchase Order # 602774	Certificate of Test: Replacement Studs IP2, September 3, 1986	
Customer Order # 46-60143	Certificate of Test: Original Studs IP3, October 7, 1966	
Purchase Order # 1025539	Certificate of Test: Replacement Studs IP3, January 22, 1999	

In comparing the elements in the applicant's AMP GALL AMP XI.M3, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

Audit Item 81:

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.

Applicant's Response (Audit Item 81):

> 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 onsite review.

Audit Item 82:

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.

Applicant's Response (Audit Item 82):

> 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, “[c]omponents 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.

Audit Item 279:

1. Check document which addresses the penetrative measures recommended in RG 1.65
2. Review documents summarizing results from past inspections.

Applicant’s Response (Audit Item 279):

RG 1.65, dated October 1973, identified material and inspection requirements for reactor vessel head studs. GALL identifies the RG 1.65 preventive measures of (1) avoiding the use of metal-plated stud bolting to prevent degradation due to corrosion or hydrogen embrittlement, and (2) to use manganese phosphate or other acceptable surface treatments and stable lubricants.

IPEC utilizes a plasma bonding technique, not the metal plating process described in RG 1.65, on the studs. The plasmabonding 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.

Staff's Findings

Based on its audit of the applicant's onsite documents and review of the applicant's responses to the staff's questions, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.12 LRA AMP B.1.31, "Reactor Vessel Head Penetration Inspection"

In the LRA, the applicant stated that the Reactor Vessel Head Penetration Inspection Program is an existing program that is consistent with GALL AMP XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (PWRs Only)."

During the audits, the staff verified that elements (1) through (6) of the Reactor Vessel Head Penetration Inspection Program are consistent with the corresponding elements of the XI.M11A AMP in the GALL Report. In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD02, Sec. 4.6	Aging Management Program Evaluation Report – Class 1 Mechanical, Reactor Vessel Head Penetration Inspection	Rev. 2
NUREG-1801, XI.M11A	Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (PWRS Only)	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 1
IP-RPT-06-00070	IPEC Alloy 600 Program, July 31, 2006	Rev. 0
2-PT-R203	Visual Examination of Reactor Vessel Head Penetrations and Head Surface for Leakage	Rev. 2
FCX-00538	Estimation of EDYs for IP2 Reactor Vessel Head by 2R17 and 2R18, July 20, 2005	Rev. 1
3-PT-R203	Visual Examination of Reactor Vessel Head Penetrations and Head Surface for Leakage	Rev. 2
SD 2	Indian Point 3, System Description, Reactor Vessel and Internals, June 25, 1999	Rev. 5
IP3-CALC-RV-03720	Estimation of Effective Degradation Years (EDYs) for IP3 Reactor Vessel Head	Rev. 2
COR-04-00244	Relaxation of First Revised Order on 12V Nozzles – IP2	October 15, 2004
COR-05-00530	Relaxation of First Revised Order on 12V Nozzles	March 18, 2005

Document	Title	Revision or Date
	– IP3	
COR-04-00111	Relaxation of First Revised Order on 12V Nozzles – IP2	February 27, 2006
COR-04-00373	Relaxation of First Revised Order on 12V Nozzles – IP3	July 17, 2006

In comparing the elements in the applicant's AMP with GALL AMP XI.M11A, the staff identified an area in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's request and the applicant's response are provided below.

Audit Item 83:

LRA AMP B. 1.3 1, "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 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)?

Applicant's Response (Audit Item 83):

> (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 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-1 14A, “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-06-001 11, COR-06-00373 were provided.

Audit Item 280:

RVH Penetration Inspection Referenced documents 5-143 - NL-05-001 and 5-144 - NL-05-044

Applicant’s Response (Audit Item 280):

Provided letters for onsite review

Staff's Findings

Based on its audit of the applicant’s onsite documents and review of the applicant's responses to the staff's questions, the staff determines that the applicant’s AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.13 LRA AMP B.1.33, “Selective Leaching”

In the LRA, the applicant stated that the Selective Leaching Program is a new program that will be consistent with GALL AMP XI.M33, “Selective Leaching of Materials.”

During the audits, the staff verified that elements (1) through (6) of the Selective Leaching Program are consistent with the corresponding elements of the XI.M33 AMP in the GALL Report. At the time of the audits, the applicant had not yet developed procedures for this new program; and the staff’s audit addressed only the applicant’s program elements and the corresponding program in the GALL Report. The applicant has committed to implement the program consistent with the GALL Report prior to the period of extended operation. In accordance with IP 71003, the staff will verify that the license renewal commitments are implemented in accordance with 10 CFR Part 54.

In addition to the supporting onsite documentation, the staff interviewed the applicant’s license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD07 Sec. 3.3	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Selective Leaching Program	Rev. 2
NUREG-1801, XI.M33	Selective Leaching of Materials	Rev. 1

Staff's Findings

Based on its audit of the applicant’s onsite documents, the staff determines that the applicant’s AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.14 LRA AMP B.1.34, “Service Water Integrity”

In the LRA, the applicant stated that the Service Water Integrity Program is an existing program that is consistent with GALL AMP XI.M20, “Open-Cycle Cooling Water System.”

During the audits, the staff verified that elements (1) through (6) of the Service Water Integrity Program are consistent with the corresponding elements of the XI.M20 AMP in the GALL Report. In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.12	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Service Water Integrity Program	Rev. 2
NUREG-1801, XI.M20	Open-Cycle Cooling Water System	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 0
SEP-SW-001	Generic Letter 89-13 Service Water Program	Rev. 0
WPO-SPEC-001	Balance-of-Plant (BOP) Eddy Current Inspection Services for the Entergy Nuclear Northeast Fleet	Rev. 1
ENDC-184	Service Water Program	

In LRA Section B.1.34, the applicant states that the Service Water Integrity Program relies on implementation of the recommendations of Generic Letter (GL) 89-13 to ensure that the effects of aging on the service water (SW) system are managed through the period of extended operation. In LRD07, the applicant states that the program addresses the aging effects of loss of material and fouling due to micro- or macro-organisms and various corrosion mechanisms on SW system components and components cooled by SW and that non-Class A/Category I heat exchangers are monitored in a similar fashion as the heat exchangers in the GL 89-13 program.

In comparing the elements in the applicant's AMP with GALL AMP XI.M20, the staff identified an area in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's request and the applicant's response are provided below.

Audit Item 84:

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.

Applicant's Response (Audit Item 84):

> 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.

Staff's Findings

The staff reviewed procedure SEP-SW-001 which outlines the program for implementing the recommendations of GL 89-13. This document integrates the separate IP2 and IP3 programs and aligns with the Entergy corporate procedure ENDC-184 “Service Water Program” procedure. The staff finds that the applicant’s GL 89-13 implementation program and activities are effective for managing aging effects on the SW system and are consistent with GALL AMP XI.M20.

Based on its audit of the applicant’s onsite documents and review of the applicant's response to the staff's question, the staff determines that the applicant’s AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.15 LRA AMP B.1.37, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)”

In the LRA, the applicant stated that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new program that will be consistent with GALL AMP XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS).”

During the audits, the staff verified that elements (1) through (6) of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program are consistent with the corresponding elements of the XI.M12 AMP in the GALL Report. At the time of the audits, the applicant had not yet developed procedures for this new program; and the staff’s audit addressed only the applicant's program elements and the corresponding program in the GALL Report. The applicant has committed to implement the program consistent with the GALL Report prior to the period of extended operation. In accordance with IP 71003, the staff will verify that the license renewal commitments are implemented in accordance with 10 CFR Part 54.

In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD02, Sec. 3.3	Aging Management Program Evaluation Report – Class 1 Mechanical, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program	Rev. 2
NUREG-1801, XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Rev. 1
License Renewal Issue No. 98-0030	Thermal Aging Embrittlement of Cast Stainless Steel Components, Letter from Christopher I. Grimes, U.S. Nuclear Regulatory Commission, to Douglas J. Walters, Nuclear Energy Institute	May 19, 2000
WCAP-14575-A	Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components	December 2000

Staff's Findings

Based on its audit of the applicant's onsite documents, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.16 LRA AMP B.1.38, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)"

In the LRA, the applicant stated that the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new program that will be consistent with GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)."

During the audits, the staff verified that elements (1) through (6) of the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program are consistent with the corresponding elements of the XI.M13 AMP in the GALL Report. At the time of the audits, the applicant had not yet developed procedures for this new program; and the staff's audit addressed only the applicant's program elements and the corresponding program in the GALL Report. The applicant has committed to implement the program consistent with the GALL Report prior to the period of extended operation. In accordance with IP 71003, the staff will verify that the license renewal commitments are implemented in accordance with 10 CFR Part 54.

In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD02, Sec. 3.2	Aging Management Program Evaluation Report – Class 1 Mechanical, Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program	Rev. 2
NUREG-1801, XI.M13	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	Rev. 1
License Renewal Issue No. 98-0030	Thermal Aging Embrittlement of Cast Stainless Steel Components, Letter from Christopher I. Grimes, U.S. Nuclear Regulatory Commission, to Douglas J. Walters, Nuclear Energy Institute	May 19, 2000
WCAP-14575-A	Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components	December 2000

Staff's Findings

Based on its audit of the applicant's onsite documents, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.2 Aging Management Programs that are Consistent with GALL with Exceptions and Enhancements

3.2.1 LRA AMP B.1.1, "Aboveground Steel Tanks"

In the LRA, the applicant stated that the Aboveground Steel Tanks Program is an existing program that is consistent, with enhancements, with GALL AMP XI.M29, "Aboveground Steel Tanks."

During the audits, the staff verified that certain elements of the Aboveground Steel Tanks Program are consistent with the corresponding elements in the XI.M29 AMP in the GALL Report. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that program elements, "scope of program," "preventive actions," and "parameters monitored or inspected," are consistent with the corresponding elements in the GALL AMP. In addition, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document Number	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.1	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Aboveground Steel Tanks	Rev. 2

Document Number	Title	Revision or Date
NUREG-1801, XI.M29	Aboveground Steel Tanks	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 1
IP-SMM-EV-103	Petroleum Bulk Storage Tank Program	Rev. 0
EN-DC-178	System Walkdowns	Rev. 1
2-PI-M009	Aboveground Petroleum Storage Tanks	Rev. 11
CE-TS-2-81	Painting of Interior and Exterior Equipment and Structures of the Conventional Portions of Unit #1 and Unit #2	Rev. 0
S-22280	Details of Shell for City Water Tank (1.5 million gallons)	Rev. 1
9321-F-1468	Refueling Water Tank Concrete Foundations	Rev. 5
B216214	300,000 Gallons Capacity Water Storage Tank	Rev. 5
A180808	Foundation and Enclosure for 200,000 Gallon Fuel Storage Tank for GT2/3	Rev. 5
TS-MS-013	IP3 Specification for Paintings and Coatings	Rev. 10 with Addendum A
9321-F-14723	Condensate Storage Tank Concrete Foundation	Rev. 3
IP3V-0245-002	Fire Protection Water Storage Tanks Plan and Elevation	Rev. 1

In comparing the elements in the applicant’s AMP with GALL AMP XI.M29, the staff identified an area in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff’s requests and the applicant’s responses are provided below.

Audit Item 107:

The gas turbine fuel storage tanks were repaired following the discovery of pitting in April 2002 using a weld overlay. What was 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?

Applicant’s Response (Audit Item 107):

> 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 air, has a repetitive task for an internal inspection, and UT cleaning that is scheduled on will it a 10 year frequency as described in the Above Ground Steel Tanks Program.

Staff's Findings

Based on its review of the applicant’s onsite documents, review of the applicant's response to the staff's question, and interviews with the applicant’s personnel, the staff determines that the applicant’s AMP elements identified above are consistent with the GALL Report. The staff’s evaluation of the "detection of aging effects," "acceptance criteria," and "monitoring and trending" elements that will be enhanced will be documented in the staff's SER Section 3.0.3.2.1.

3.2.2 LRA AMP B.1.2, "Bolting Integrity"

In the LRA, the applicant stated that the Bolting Integrity Program is an existing program that is consistent, with enhancement, with GALL AMP XI.M18, "Bolting Integrity."

During the audits, the staff verified that certain elements of the Bolting Integrity Program are consistent with corresponding elements in the XI.M18 AMP in the GALL Report. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that program elements, "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in the GALL AMP. In addition, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document Number	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.2	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Bolting Integrity Program	Rev. 2
NUREG-1801, XI.M18	Bolting Integrity	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 1
EN-DC-178	System Walkdowns	Rev. 1
ENN-DC-150, Rev. 1	Condition Monitoring of Maintenance Rule Structures	
EPRI NP-5769	Degradation and Failure of Bolting in Nuclear Power Plants	
0-MS-411	Torquing of Mechanical Fasteners	Rev. 0
IP-SMM-DC-907	ASME Code Section XI – Repair/Replacement Program	Rev. 2
2-PT-R075	RCS Integrity Inspection	Rev. 12
IP2-RPT-03-00006	IP2 Third Ten-year Inspection Interval Inservice Inspection Program	Rev. 1
SE-Q-12.707	Carbon Steel Fastener Inspection Program	Rev. 0
IP3-RPT-UNSPEC-03247	IP3 Inservice Inspection Program Third Ten-year Interval	Rev. 3
3-PT-R131	RCS Integrity Leak Test	Rev. 11

In comparing the elements in the applicant's AMP with GALL AMP XI.M18, the staff identified an area in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's request and the applicant's response are provided below.

<u>Audit Item 108</u>:

Does Entergy have a bolting expert as recommended in the EPRI documents?

Applicant's Response (Audit Item 108):

> EPRI TR-104213, Bolted Joint Maintenance & Applications Guide, recommends providing an onsite 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.

Staff's Findings

Based on its review of the applicant's onsite documents, review of the applicant's response to the staff's question, and interviews with the applicant's personnel, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report. The staff's evaluation of the "preventive actions" element that will be enhanced will be documented in the staff's SER Section 3.0.3.2.2.

3.2.3 LRA AMP B.1.9, "Diesel Fuel Monitoring"

In the LRA, the applicant stated that the Diesel Fuel Monitoring Program is an existing program that is consistent, with enhancements and exceptions, with GALL AMP XI.M30, "Fuel Oil Chemistry."

During the audits, the staff verified that certain elements of the Diesel Fuel Monitoring Program are consistent with the corresponding elements in the XI.M30 AMP in the GALL Report. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that program element "corrective actions" is consistent with the corresponding element in the GALL AMP. In addition, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document Number	Title	Revision or Date
IP-RPT-06-LRD07	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Diesel Fuel Monitoring Program	Rev. 2
NUREG-1801, XI.M30	Fuel Oil Chemistry	Rev. 1
IP-RPT-06-LRD05,	Operating Experience Review Report	Rev. 1
EN-LI-102	Corrective Action Process	Rev. 8
EN-LI-121	Entergy Trending Process	Rev. 6
0-CY-1500	Chemistry Sampling Locations	Rev. 3
0-CY-1810	Diesel Fuel Oil Monitoring	Rev. 4
0-CY-3318	Water and Sediment in Fuel Oil	Rev. 3
IP-SMM-EV-103	Petroleum Bulk Storage Tank Program	Rev. 0
2-CY-1560	Diesel Fuel Oil Sampling	Rev. 0
2-GNR-009-ELC	Emergency Diesel Generator Main Fuel Oil Tank Maintenance	Rev. 0
3-CY-2615	Adding Chemicals to Auxiliary Systems	Rev. 0

Document Number	Title	Revision or Date
GNR-024-ELC	IP3 Emergency Diesel Generator 10 Year Inspection for Fuel Oil Supply Tank Cleaning	Rev. 0

Staff's Findings

The staff interviewed the applicant’s technical staff and reviewed the program basis document which provides an assessment of the AMP elements’ consistency with GALL AMP XI.M30. Specifically, the staff reviewed the program elements contained in associated basis documents to determine their consistency with GALL AMP XI.M30.

In addition, the staff reviewed American Society for Testing and Materials (ASTM) Standards D 4057, “Standard Practice for Manual Sampling of Petroleum and Petroleum Products,” 1995; D 975, “Standard Specification for Fuel Oils,” 2006; D1796, “Standard Test method for Water and Sediment in Fuel Oils by the Centrifuge Method,” 2004; D 2276, “Standard Test method for Particulate Contaminant in Aviation Fuel by Line Sampling,” 2000; D 6217, “Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration,” 2003 and D 2709-96 Standard Test Method for Water and Sediment in Middle Distillate Fuels by Centrifuge, 1996.

The staff verified that the applicant’s diesel fuel monitoring program includes sampling and analysis activities on diesel fuel that are in accordance with ASTM standard D 4057 for sampling, D 975 for analysis, D 1796 for water and sediment monitoring, and D 6217 for particulates monitoring. These activities are consistent with the recommendations in NUREG-1801.

The emergency diesel generators (EDGs), gas turbine generators, diesel fire pump, Appendix R diesel generators, and security diesel generator fuel oil storage tanks are sampled and analyzed quarterly (once per 80 days per procedure) and each shipment is sampled and tested prior to being added to a bulk fuel oil storage tank. The EDGs, diesel fire pumps, Appendix R diesel generators, and security diesel generator fuel oil day tanks are sampled and analyzed monthly. The staff reviewed plant procedures 0-CY-1810, “Diesel Fuel Oil Monitoring,” Revision 4, 0-CY-1500, “Chemistry Sampling Locations,” Revision 3, and 2-CY-1560, “Diesel Fuel Oil Sampling,” Revision 0, and confirmed the sampling frequencies. The staff also verified that the sampling frequencies for the safety-related EDGs are in accordance with Indian Point Technical Specifications.

Based on its review of the applicant’s onsite documents and interviews with the applicant’s personnel, the staff determines that the applicant’s element identified above is consistent with the GALL Report. The staff’s evaluation of the "preventive actions," "detection of aging effects," "monitoring and trending," and "acceptance criteria" elements that will be enhanced and the "scope of program," "preventive actions," "parameters monitored or inspected," and "acceptance criteria" elements to which the applicant has taken exception will be documented in the staff’s SER Section 3.0.3.2.4.

3.2.4 LRA AMP B.1.11, "External Surfaces Monitoring"

In the LRA, the applicant stated that the External Surfaces Monitoring Program is an existing program that is consistent, with enhancement, with GALL AMP XI.M36, "External Surfaces Monitoring."

During the audits, the staff verified that certain elements of the External Surfaces Monitoring Program are consistent with the corresponding elements in the XI.M36 AMP in the GALL Report. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that program elements, "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in the GALL AMP. In addtion, the staff interviewed the applicant's technical staff and reviewed the following onsite documents:

Document	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.6	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, External Surfaces Monitoring	Rev. 2
NUREG-1801, XI.M36	External Surfaces Monitoring	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 0
EN-DC-178	System Walkdowns	Rev. 1
EN-LI-102	Corrective Action Process	Rev. 8
EN-MS-S-011-MULTI	Conduct of System Engineering	Rev. 2

In comparing the elements in the applicant's AMP with GALL AMP XI.M36, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's request and the applicant's response are provided below.

Audit Item 38:

Give details of surfaces included in the External Surfaces Monitoring Program accessible only when the insulation is removed.

Applicant's Response (Audit Item 38):

> 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.

Audit Item 154:

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 degradation 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 subject to an AMR. Will the revision include inclusion of these attributes?

Applicant’s Response (Audit Item 154):

> 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.

Audit Item 155:

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?

Applicant’s Response (Audit Item 155):

> 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.

Staff's Findings

Based on its review of the applicant’s onsite documents, review of the applicant's responses to the staff's questions, and interviews with the applicant’s personnel, the staff determines that the applicant’s AMP elements identified above are consistent with the GALL Report. The staff’s evaluation of the "scope of program" element that will be enhanced will be documented in the staff’s SER Section 3.0.3.2.5.

3.2.5 LRA AMP B.1.12, "Fatigue Monitoring"

In the LRA, the applicant stated that the Fatigue Monitoring Program is an existing program that is consistent, with exception and enhancement, with GALL AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary."

During the audits, the staff verified that certain elements of the Fatigue Monitoring Program are consistent with the corresponding elements in the X.M1 AMP in the GALL Report. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that program elements, "scope of program," "preventive actions," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in the GALL AMP. In addition, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD02, Sec. 4.2	Aging Management Program Evaluation Report – Class 1 Mechanical, Fatigue Monitoring	Rev. 2
NUREG-1801, X.M1	Metal Fatigue of Reactor Coolant Pressure Boundary	Rev. 1
IP-RPT-06-LRD05,	Operating Experience Review Report	Rev. 1
WCAP-12191	Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Final Report for Indian Point Unit 2, July, 1992	Rev. 2
WCAP-12937	Structural Evaluation of Indian Point Units 2 and 3 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification	May 1991
2-PT-2Y015	Thermal Cycle Monitoring Program	Rev. 1
3PT-M051	Plant Operation Information	Rev. 9

In comparing the elements in the applicant's AMP with GALL AMP X.M1, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below

<u>Audit Item 39</u>:

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?

Applicant's Response (Audit Item 39):

(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 onsite 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 onsite.

Audit Item 40:

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 the corrective action?

Applicant's Response (Audit Item 40):

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.

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.

Audit Item 41:

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?

Applicant’s Response (Audit Item 41):

(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 onsite.

Audit Item 42:

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 reevaluation.

(b) Under what circumstances that IP2 charging nozzles were re-evaluated? Please describe the re-evaluations process for IP2 charging nozzles.

Applicant’s Response (Audit Item 42):

(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-1 2191, Revision 3, “Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Final Report for Indian Point 2”.

Audit Item 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?

Applicant's Response (Audit Item 164):

> 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

Staff's Findings

Based on its review of the applicant's onsite documents, review of the applicant's responses to the staff's questions, and interviews with the applicant's personnel, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report. The staff's evaluation of the "parameters monitored or inspected" element that will be enhanced and the "detection of aging effects" element to which the applicant has taken exception will be documented in the staff's SER Section 3.0.3.2.6.

3.2.6 LRA AMP B.1.13, "Fire Protection"

In the LRA, the applicant stated that the Fire Protection Program is an existing program that is consistent, with exception and enhancements, with GALL AMP XI.M26, "Fire Protection."

During the audits, the staff verified that certain elements of the Fire Protection Program are consistent with the corresponding elements in the XI.M26 AMP in the GALL Report. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that program elements "preventive actions" and "monitoring and trending" are consistent with the corresponding elements in the GALL AMP. In addition, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.7	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Fire Protection Program	Rev. 2
NUREG-1801, XI.M26	Fire Protection	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 0
SAO-703	IP2 Fire Protection Impairment Criteria and Surveillance	Rev. 25
2-PI-Q001	Fire Separation Barriers	Rev. 9
2PT-2Y017	Penetration Fire Barrier Seal Inspections	Rev. 0
2-PT-R201	RCP Oil Collection System	Rev. 0
2-PT-SA020	Swing Fire Doors	Rev. 0

Document	Title	Revision or Date
2-PT-A048	Rollup Fire Doors	Rev. 0
2-PT-W005	Diesel Fire Pump	Rev. 18
2-PT-M040	Diesel Fire Pump	Rev. 24
2-ENG-003-FIR	Detroit Diesel V-71; Emergency Fire Pump Diesel PM	Rev. 0
PT-EM19	IP2 Cable Spreading Room Halon System	Rev. 10
PT-SA13	Cable Spreading Room Halon System	Rev. 9
AP-64.1	Fire Protection/Appendix R Systems and Components Governed by Technical Requirements Manual and Technical Specifications	Rev. 2
3-PT-M042B	Diesel Fire Pump Test	Rev. 4
3PT-R100	Fire Barrier Penetration Seal Inspection	Rev. 6
3PT-R100A	Controlled Barrier Inspection	Rev. 1
3PT-R102	Fire Barrier Wrap/Radiant Energy Shield Inspection	Rev. 4
3-PT-2Y004	CO_2 System Test for Cable Spreading and Switchgear Rooms	Rev. 2
3-PT-2Y005	CO_2 System Test for 31, 32, and 33 EDG Rooms	Rev. 1
3-ENG-001-FIR	Diesel Driven Fire Pump Engine Major Preventive Maintenance Inspection	Rev. 8
3-ENG-002-FIR	Diesel Driven Fire Pump Engine Minor Preventive Maintenance Inspection	Rev. 7
3-PT-SA070	Fire Door Inspection	Rev. 0

In comparing the elements in the applicant's AMP with GALL AMP XI.M26, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

Audit Item 104:

Provide Approval Package for SAO-703, Rev 25.

Applicant's Response (Audit Item 104):

Approval package per EN-DC-128 provided for SAO-703, Rev 25.

Audit Item 150:

The exception to NUREG-1801 for B.1.13 regarding the frequency of functional testing of Halon (IP2) and CO_2 (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?

Applicant's Response (Audit Item 150):

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 CO_2 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 CO_2 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-EM 19, 3-PT-2Y004 and 3-PT-2Y005). The condition reporting database was similarly reviewed and revealed no adverse indications of material degradation.

Audit Item 151:

What is the original licensing basis for the functional testing frequency of CO_2 and Halon systems at IP2 and IP3?

Applicant's Response (Audit Item 151):

The original licensing basis for the functional testing frequency of CO_2 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 CO_2 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).

Audit Item 157:

What is the current frequency of inspection for fire barrier penetrations and what is the % sample to be inspected?

Applicant's Response (Audit Item 157):

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.

Audit Item 158:

Fire separation barrier inspections (2-PI-QO01 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 layers of Kaowool. Is this guidance (GL 2006-03) incorporated into the barrier inspection program and specifically where?

Applicant's Response (Audit Item 158):

The failure mode cited in Generic Letter 2006-03 specifically the potential shrinkage of the outer covering, exposing the interior surfaces or layers to the fire, relate to the performance and response of a Hemyc fire barrier wrap under fire conditions which were installed in accordance with vendor requirements. These requirements were similarly used during the installation of the Hemyc fire barrier wrap at IP2 and IP3.

Periodic test 2-PI-Q001 ensures through a visual inspection that the material condition of the wrap is satisfactory (i.e., the wrap is not missing, punctured or torn, the wrap is not oil soaked or shows evidence of other chemical contamination and that it is properly banded as required), thereby consistent with the initial pre-fire condition.

Audit Item 161:

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)

Applicant's Response (Audit Item 161):

> 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 3.3.2-12-1P2 and 3.3.2-12-1P3.

Staff's Findings

Based on its review of the applicant's onsite documents, review of the applicant's responses to the staff's questions, and interviews with the applicant's personnel, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report. The staff's evaluation of the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" elements that will be enhanced and the "detection of aging effects" element to which the applicant has taken exception will be documented in the staff's SER Section 3.0.3.2.7.

3.2.7 LRA AMP B.1.14, "Fire Water System"

In the LRA, the applicant stated that the Fire Water System Program is an existing program that is consistent, with exception and enhancements, with GALL AMP XI.M27, "Fire Water System."

During the audits, the staff verified that certain elements of the Fire Water System Program are consistent with the corresponding elements in the XI.M27 AMP in the GALL Report. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that program elements "scope of program," "preventive actions," "monitoring and trending," and "operating experience" are consistent with the corresponding elements in the GALL AMP. In addition, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.8	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Fire Water System Program	Rev. 2
NUREG-1801, XI.M27	Fire Water System	Rev. 1,
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 0
EN-AD-103	Document Control and Records Management Activities	Rev. 5
SAO-703	IP2 Fire Protection Impairment Criteria and Surveillance	Rev. 24
AP-64.1	Fire Protection/Appendix R Systems and Components Governed by Technical Requirements Manual and Technical Specifications	Rev. 2

Document	Title	Revision or Date
FP-T-1*888	5 Year Inspection (Internal) IAW NFPA 25 of FP-T-1	
FP-T-2*888	5 Year Inspection (Internal) IAW NFPA 25 of FP-T-2	
3-PT-R113	High Pressure Water Fire Protection System Flush and Loop Flow Determinations	Rev. 10

In comparing the elements in the applicant's AMP with GALL AMP XI.M27, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

Audit Item 103:

Please provide 2006 Fire Water System Flow Test.

Applicant's Response (Audit Item 103):

2006 Fire Water System Flow Test provided.

Audit Item 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?

Applicant's Response (Audit Item 105):

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

Audit Item 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.

Applicant's Response (Audit Item 106):

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

Audit Item 111:

Provide Fire Protection System Impairment Summary.

Applicant’s Response (Audit Item 111):

Provided the fire protection system impairment summary as of 6-10-07.

Audit Item 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)

Applicant’s Response (Audit Item 149):

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 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.

Audit Item 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.

Applicant's Response (Audit Item 152):

> 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.

Audit Item 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)

Applicant's Response (Audit Item 153):

> IP2 and IP3 maintain independent fire protection systems and the "cross connect" is not considered for compliance with IP2 or IP3 fire protection requirements.

Staff's Findings

Based on its review of the applicant's onsite documents, review of the applicant's responses to the staff's questions, and interviews with the applicant's personnel, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report. The staff's evaluation of the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" elements that will be enhanced and the "detection of aging effects" element to which the applicant has taken exception will be documented in the staff's SER Section 3.0.3.2.8.

3.2.8 LRA AMP B.1.16, “Flux Thimble Tube Inspection”

In the LRA, the applicant stated that the Flux Thimble Tube Inspection Program is an existing program that is consistent, with enhancements, with GALL AMP XI.M37, “Flux Thimble Tube Inspection.”

During the audits, the staff verified that certain elements of the Flux Thimble Tube Inspection Program are consistent with the corresponding elements in the XI.M37 AMP in the GALL Report. To verify the applicant’s claim of consistency, the staff reviewed the applicant’s onsite documentation supporting the applicant’s conclusion that program elements, “scope of program,” “‘preventive actions,” “parameters monitored or inspected,” and “detection of aging effects,” are consistent with the corresponding elements in the GALL AMP. In addition, the staff interviewed the applicant’s license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD02, Sec. 4.3	Aging Management Program Evaluation Report – Class 1 Mechanical, Flux Thimble Tube Inspection	Rev. 2
NUREG-1801, XI.M37	Flux Thimble Tube Inspection	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 1
WCAP-12866	Bottom Mounted Instrumentation Flux Thimble Wear, January 1991	
Work Order IP2-03-17424	Perform Eddy Current Testing on Flux Thimble Tubes	
RE-ICI-910625	Calculation of Incore Thimble Tube Wear	Rev. 0
THI-002-RVI	Eddy Current Inspection of Incore Detector Thimble Tubes	Rev. 2
MRS-SSP-1166-INT	BMI Flux Thimble Tube Repositioning, Capping, and High Pressure Seal Inspection at Indian Point #3	Rev. 0
IP-CALC-07-00038	Re-inspection Frequency for the IP3 Thimble Tubes	Rev. 0

In comparing the elements in the applicant’s AMP with GALL AMP XI.M37, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff’s requests and the applicant’s responses are provided below.

<u>Audit Item 50</u>:

LRA AMP B.1.16, "Program Description" states:

“An NDE methodology, such as eddy current testing (ECT), or other similar inspection method is used to monitor for wear of the flux thimble tubes. This program implements the recommendations of NRC Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors.”

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?

Applicant's Response (Audit Item 50):

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

Audit Item 277:

Provide the referenced documents:

5-222: IP-DSE-01-058
5-224: IP-RPT-06-001824

Applicant's Response (Audit Item 277):

Reports IP-DSE-01-058, Review of R1 1 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.

Staff's Findings

Based on its review of the applicant's onsite documents, review of the applicant's responses to the staff's questions, and interviews with the applicant's personnel, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report. The staff's evaluation of the "monitoring and trending," "acceptance criteria," and "corrective actions" elements that will be enhanced will be documented in the staff's SER Section 3.0.3.2.9.

3.2.9 LRA AMP B.1.19, "Masonry Wall"

In the LRA, the applicant stated that the Masonry Wall Program is an existing program that is consistent, with enhancement, with GALL AMP XI.S5, "Masonry Wall Program."

During the audits, the staff verified that certain elements of the Masonry Wall Program are consistent with the corresponding elements in the XI.S5 AMP in the GALL Report. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that program elements, "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in the GALL AMP. In addition, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD08, Sec. 3.4	Aging Management Program Evaluation Report Structural/Civil, Masonry Wall Program	Rev. 2
NUREG-1801, XI.S5	Masonry Wall Program	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 0
ENN-DC-150	Condition Monitoring of Maintenance Rule Structures	Rev. 1

Staff's Findings

The staff reviewed the program basis documents and confirmed that the Masonry Wall Program is an existing program that manages aging effects for all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. The program basis documents refer to the Entergy document ENN-DC-150 for the specific details of the existing program that is credited. This existing program is the Condition Monitoring of Maintenance Rule Structures which is a program that establishes the requirements for monitoring the various structures at IP2/IP3 in accordance with 10 CFR 50.65, The Maintenance Rule. Therefore, instead of a separate masonry wall AMP, Entergy credits the existing Condition Monitoring of Maintenance Rule Structures program. This approach is consistent with the GALL report, provided the attributes of Entergy's program are consistent with the 10 elements of GALL AMP XI.S5 (Masonry Wall Program).

The staff's review of the program basis documents confirmed that this AMP monitors masonry walls for cracking in joints and blocks that could potentially affect wall qualification. These program basis documents refer to the Condition Monitoring of Maintenance Rule Structures program for further information. Section 5.8 of that program states that block walls shall be inspected for cracks, unsealed penetrations, missing or broken blocks, and missing mortar. The checklist presented in Attachment 9.5 of that program includes parameters such as visible cracks, spalling or scaling, exposed reinforcement, missing blocks or mortar, broken blocks, corroded or loose inserts, degradation of wall connections including steel braces or supports.

The program basis documents indicate that the applicant's inspectors have appropriate levels of experience and training and are degreed engineers with a thorough understanding of structures and materials of construction. The program basis documents refer to the Condition Monitoring of Maintenance Rule Structures program for further information. Section 5.8 of that program indicates that the inspection engineer shall, as a minimum, be knowledgeable or trained in the design, evaluation, and performance requirements of structures; be a degreed engineer; and have at least 5 years structural design/analysis/field evaluation experience. Further, the documents state that the program administrator shall have the same minimum qualifications except for experience, where 10 years of related experience or professional engineer registration with 5 years related experience are required.

The program basis documents indicate that the inspections occur at least once every five years. The frequency of inspection is selected to ensure there is no loss of intended function between inspections. The program basis documents refers to the Condition Monitoring of Maintenance Rule Structures program) for further information. Section 1.0 of that program specifies that a baseline condition assessment is performed, followed by inspections at 5 year intervals, or more frequently if necessary to monitor observed degradation. Certain normally inaccessible areas may have an extended interval, such as 10 years, due to the potential risk and extensive work involved to complete the inspection.

The Condition Monitoring of Maintenance Rule Structures program contains provisions that address monitoring and trending. Section 5.5 requires that if degradations are discovered, they are documented so that future monitoring can determine a trend. In accordance with RG 1.160, the inspection frequency is increased if significant degradation is observed. This is consistent with the GALL report.

The program basis documents indicates that a general examination of each wall is performed to identify indications of degradation, such as cracking, missing mortar, or degraded structural steel components. Potential non-conforming conditions identified during the course of an inspection are noted and a condition report is initiated. The program basis documents refer to the Condition Monitoring of Maintenance Rule Structures program for further information. Section 5.8 and Attachment 9.5 of that program identify the various types of degradation that need to be inspected such as cracking, spalling, scaling, exposed reinforcement, missing block or mortar and degradation of masonry wall braces or supports. In addition, Section 5.5 specifies that if degradations are discovered then “Give details such as crack width and length, amount of rust, area of spalls, etc., for future should reference.” Section 5.5 also specifies that documents such as condition report (CR), work order task (WOT), Work Order (WO) are used to identify and resolve areas of concern. Any area or structure showing significant degradation is required by this program “to be further evaluated by the Corrective Action Process or NDE testing or structural analysis to show acceptability as-is.”

Based on its review of the applicant’s onsite documents and interviews with the applicant’s personnel, the staff determines that the applicant’s AMP elements identified above are consistent with the GALL Report. The staff’s evaluation of the "scope of program" element that will be enhanced will be documented in the staff’s SER Section 3.0.3.2.10.

3.2.10 LRA AMP B.1.20, “Metal-Enclosed Bus Inspection”

In the LRA, the applicant stated that the Metal-Enclosed Bus Inspection Program is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.E4, “Metal Enclosed Bus.”

During the audits, the staff verified that certain elements of the Metal-Enclosed Bus Inspection Program are consistent with the corresponding elements in the XI.E4 AMP in the GALL Report. To verify the applicant’s claim of consistency, the staff reviewed the applicant’s onsite documentation supporting the applicant’s conclusion that program elements “preventive actions” and “monitoring and trending” are consistent with the corresponding elements in the GALL AMP. In addition, the staff interviewed the applicant’s license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD09, Sec. 4.2	Aging Management Program Evaluation Report–Electrical, Metal-Enclosed Bus Inspection	Rev. 2
NUREG-1801, XI.E4	Metal Enclosed Bus	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 0
0-ELC-403-BUS	Inspection and Cleaning of 480 Volt Bus Duct	Rev. 0
0-ELC-404-BUS	Inspection and Cleaning of 6.9kV Bus Duct	Rev. 0
EN-LI-102	Corrective Action Process	Rev. 9
MS-104	Inspection and Cleaning of Bus Bars, Contacts, Ground Connections, Wiring and Insulators	Rev 2

In comparing the elements in the applicant's AMP with GALL AMP XI.E4, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

Audit Item 124:

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 microohm 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.

Applicant's Response (Audit Item 124):

> As indicated in LRA Section B.1.20, the "Metal-Enclosed Bus Inspection Program" is consistent with the inspection methods described in NUREG-1801. The program description in LRA Section B.1.20 will be clarified to describe the alternate tests and inspections discussed in NUREG-1801, Section XI.E4. Visual inspections will continue to be used for bolted connections as appropriate.
>
> The site AMP evaluation report will also be clarified as discussed for LRA B.1.20. The program description, and Items 4(b), and 6(b) will be modified to address the inspection methods besides visual that are discussed in NUREG-1801, Section XI.E4. Item 3(b) does not require a change, since this item is consistent with NUREG-1801. The inspection methods used in the existing site procedures will be reflected in the site AMP evaluation report.
>
> LRA Section B.1.20, Metal Enclosed Bus Inspection, Program Description, second paragraph, and the enhancements are revised as follows.

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

Enhancements
Attributes Affected: 3. Parameters Monitored or Inspected; 4. Detection of Aging Effects; 6. Acceptance Criteria
Revise appropriate procedures to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material.

Attributes Affected: 4. Detection of Aging Effects
Revise appropriate procedures to inspect bolted connections at least once every five years if only performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation.

LRA Sections A.2.1.19 and A.3.1.19, Metal Enclosed Bus Inspection Program, second paragraph, is revised as follows.

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

LRA Sections A.2.1.19 and A.3.1.19, Metal Enclosed Bus Inspection Program, third paragraph, second bullet is revised as follows.

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

Clarification to be incorporated into the LRA

Audit Item 125:

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.

Applicant's Response (Audit Item 125):

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 CE 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 480V 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.

Audit Item 133:

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?

Applicant's Response (Audit Item 133):

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.

Staff's Findings

Based on its review of the applicant's onsite documents, review of the applicant's responses to the staff's questions, and interviews with the applicant's personnel, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report. The staff's evaluation of the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" elements that will be enhanced and the "parameters monitored or inspected" and "detection of aging effects" elements to which the applicant has taken exception will be documented in the staff's SER Section 3.0.3.2.11.

LRA AMP B.1.26, "Oil Analysis"

In the LRA, the applicant stated that the Oil Analysis Program is an existing program that is consistent, with exception and enhancements, with GALL AMP XI.M39, "Lubricating Oil Analysis Program."

During the audits, the staff verified that certain elements of the Oil Analysis Program are consistent with the corresponding elements in the XI.M39 AMP in the GALL Report. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that program element "scope of program" is consistent with the corresponding element in the GALL AMP. In addition, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.10	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Oil Analysis Program	Rev. 2
NUREG-1801, XI.M39	Lubricating Oil Analysis Program	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 0
EN-DC-310	Predictive Maintenance Program	Rev. 0
0-LUB-401-GEN	Lubrication of Plant Equipment	Rev. 1
0-CY-3322	Determination of Water and Sediment in Lubricating Oils	Rev. 1
IP PdM Activity Matrix	Indian Point PdM Activity Matrix (Predictive Maintenance)	
0-PMP-401-RCS	Reactor Coolant Pump Seal Package Inspection	Rev. 1
IP-SMM-DC-911	IPEC Lubrication Program	Rev. 0
	PDMA Corporation Reports	
IP2-NPMEL-PMO-6630	PM for 1 Year Oil Sample and Analysis of Safety Injection Pump Lube Oil (21SIP)	
IP2-NPMEL-PMO-6636	PM for 1 Year Oil Sample and Analysis of Safety Injection Pump Lube Oil (22SIP)	
IP2-NPMEL-PMO-6643	PM for 1 Year Oil Sample and Analysis of Safety Injection Pump Lube Oil (23SIP)	

Document	Title	Revision or Date
IP2-NPMEL-PMO-11203	PM for 3 Month Oil Sample and Analysis of Charging Pump 21CHP Crankcase	
IP2-NPMEL-PMO-11212	PM for 3 Month Oil Sample and Analysis of Charging Pump 22CHP Crankcase	
IP2-NPMEL-PMO-11217	PM for 3 Month Oil Sample and Analysis of Charging Pump 23CHP Crankcase	
IP2-TEST95-PDM-21AFP	PM for 1 Year Oil Sample and Analysis of Auxiliary Feedwater Pump 21	
IP2-TEST95-PDM-22AFP	PM for 1 Year Oil Sample and Analysis of Auxiliary Feedwater Pump 22	
2-PT-M021A	Emergency Diesel Generator 21 Load Test	Rev 14,
2-PT-M021B	Emergency Diesel Generator 22 Load Test	Rev 14
2-PT-M021A	Emergency Diesel Generator 2(1) Load Test	Rev 12
2-CY-2625	General Plant Systems Specifications and Frequencies	Rev. 7
31 SI PUMP *PDM* LUB	PM for 1 Year Oil Sample and Analysis of Safety Injection Pump Lube Oil	
32 SI PUMP *PDM* LUB	PM for 1 Year Oil Sample and Analysis of Safety Injection Pump Lube Oil	
33 SI PUMP *PDM* LUB	PM for 1 Year Oil Sample and Analysis of Safety Injection Pump Lube Oil	
31 CHARGING PUMP *PDM* LUB	PM for 6 Month Oil Sample and Analysis of Charging Pump Frame and Fluid Drive	
32 CHARGING PUMP *PDM* LUB	PM for 6 Month Oil Sample and Analysis of Charging Pump Frame and Fluid Drive	
33 CHARGING PUMP *PDM* LUB	PM for 6 Month Oil Sample and Analysis of Charging Pump Frame and Fluid Drive	
31 ABFP SMPL *R* 591	PM 6 Month Sample and Analysis of Auxiliary Feedwater Pump 31	
32 ABFP SMPL *R* 591	PM 6 Month Sample and Analysis of Auxiliary Feedwater Pump 32	
32 ABFP(T) SMPL *R* 591	PM 6 Month Sample and Analysis of Auxiliary Feedwater Pump Turbine	
33 ABFP SMPL *R* 591	PM 6 Month Sample and Analysis of Auxiliary Feedwater Pump 33	
EDG31 *PDM* LUB	1 Month Oil Sample and Analysis – Crankcase	
EDG32 *PDM* LUB	1 Month Oil Sample and Analysis – Crankcase	
EDG33 *PDM* LUB	1 Month Oil Sample and Analysis – Crankcase	
ARDG *PDM* LUB	1 Month Oil Sample and Analysis – Crankcase	
3-CY-2625	General Plant Systems Specifications and Frequencies	Rev. 5

Staff's Findings

Based on its review of the applicant’s onsite documents and interviews with the applicant’s personnel, the staff determines that the applicant’s AMP element identified above is consistent with the GALL Report. The staff’s evaluation of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions" elements that will be enhanced and the "parameters monitored or inspected" element to which the applicant has taken exception will be documented in the staff's SER Section 3.0.3.2.12.

3.2.11 LRA AMP B.1.36, "Structures Monitoring"

In the LRA, the applicant stated that the Structures Monitoring Program is an existing program that is consistent, with enhancements, with GALL AMP XI.S6, "Structures Monitoring Program."

During the audits, the staff verified that certain elements of the Structures Monitoring Program are consistent with the XI.S6 AMP in the GALL Report. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that program elements "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in the GALL AMP. In addition, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD08, Sec. 3.3	Aging Management Program Evaluation Report Structural/Civil, Structures Monitoring Program	Rev. 2
NUREG-1801, XI.S6	Structures Monitoring Program	Rev. 1,
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 1
ENN-DC-150	Condition Monitoring of Maintenance Rule Structures	Rev. 1
License Renewal Issue No. 98-0030	Thermal Aging Embrittlement of Cast Stainless Steel Components, Letter from Christopher I. Grimes, U.S. Nuclear Regulatory Commission, to Douglas J. Walters, Nuclear Energy Institute, May 19, 2000.	

In comparing the elements in the applicant's AMP with GALL AMP XI.S6, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

Audit Item 88:

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.

Applicant's Response (Audit Item 88):

(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)(1) 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 II1.A6-7. The parameters monitored from the GALL XI.S7 program applicable to loss of material are consistent with those monitored by the Structures Monitoring Program. The guidance for inspections of concrete in Section C.2 of RG 1.127 is consistent with the guidance in ACI 349.3 used in the Structures Monitoring Program. Based on the above discussion, the parameters monitored include loss of material, cracking, movement (settlements and deflections). Since there are no earthen structures at IPEC in scope of the license renewal, GALL XI.S7 attributes applicable to earthen structures are not applicable for IPEC water control structures.

4) Detection of Aging - GALL XI.S7 identifies visual inspection methods as the primary method used to detect aging. The Structures Monitoring similarly uses visual inspection methods as the primary method used to detect aging in concrete structural components. GALL XI.S7 identifies inspection intervals of five years. The Structures Monitoring Program identifies similar inspection intervals of five years for accessible areas and opportunistic inspections for buried components. Guidance will be added to the Structures Monitoring Program to inspect inaccessible concrete areas that are exposed by excavation for any reason.

5) Monitoring and Trending - Monitoring is by periodic inspection for both the GALL XI.S7 and Structures Monitoring Programs.

6) Acceptance Criteria - Acceptance criteria in NUREG-1801, XI.S7 says plant-specific acceptance criteria based on Chapter 5 of ACI 349.3R-96 are acceptable. Appropriate guidance is provided in the Structures Monitoring Program to ensure corrective measures are identified prior to loss of intended function. The guidance in the Structures Monitoring Program includes reference to ACI 349.3R-96. XI.S7 acceptance criteria related to earthen structures are not applicable.

7-9) The corrective actions, confirmation process and administrative control attributes of the Structures Monitoring Program and the GALL XI.S7 program are consistent.

10) Operating Experience - The operating experience relevant to the effectiveness of the Structures Monitoring Program is presented in Appendix B of the application and is consistent with the operating experience described in GALL XI.S7.

Therefore, the attributes of the NUREG-1801 XI.S7, Water Control Structures, aging management program pertaining to the intake structure are incorporated within the AMP B.1.36 (Structures Monitoring Program).

The following is added to commitment 25: "Enhance the Structures Monitoring Program 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

Audit Item 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 Structures AMPS, 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 Degradation:

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 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.

Applicant's Response (Audit Item 358):

> 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 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, 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 1P3-05-21329 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.

<u>Audit Item 359</u>:

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 Structures AMPS, 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 Leakage:

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 IP2 has a long-term degradation issue with leakage from the Refueling Cavity Liner. The liner 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.

Applicant's Response (Audit Item 359):

> 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 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.

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.

<u>Audit Item 360</u>:

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 Stuctures AMPS, 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 Crack/Leak 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.

Applicant's Response (Audit Item 360):

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 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.

Staff's Findings

The staff reviewed the program basis documents and confirmed that the Structures Monitoring Program at IP2 and IP3 is an existing program that performs inspections in accordance with 10 CFR 50.65 (Maintenance Rule), as addressed in RG 1.160 and NUMARC 93-01. This is consistent with the GALL report.

The staff reviewed the plant basis documents (PBD) and additional referenced documents, to evaluate the adequacy of the “monitoring and trending” program element for all structural components. The applicant stated that structures are monitored in accordance with 10 CFR 50.65 (a)(2), provided there is not significant degradation; if acceptance criteria are exceeded, the structure is monitored in accordance with the applicant's 10 CFR 50.65(a)(1) action plan. The applicant further stated that structures classified as “unacceptable” will be evaluated by the “Expert Panel” for goal setting and categorized as a 10 CFR 50.65(a)(1) system in accordance with the Maintenance Rule Procedure, ENN-DC-121. The unacceptable classification is defined as those structures which are degraded such that they are not capable of performing their structural functions, including the protection or support of safety-related systems or components. The staff finds that the "monitoring and trending" element is consistent with the GALL report.

The staff reviewed the PBD, to evaluate the adequacy of the “acceptance criteria” program element for each structure/aging effect combination for the various structures and structural components. Attachment 1 to the PBD provides a tabulation of the structural material, aging effect, parameters monitored, detection of aging, and acceptance criteria. For each structural material/aging effect, the acceptance criteria are provided. The acceptance criteria are generally descriptive in nature, such as: absence of cracks, excessive rust bleeding, staining or discoloration, abrasion, erosion, cavitation, spalling, scaling, leaching, excessive settlement, corrosion of reinforcement, and degraded waterproof membranes, all for concrete elements. All of the acceptance criteria refer to a footnote which states that the limits are based on criteria stated in ACI 349.3R-96 or ANSI/ASCE 11-99 or as identified in specific site procedures. The staff finds that the "acceptance criteria" element is consistent with the GALL report.

Based on its review of the applicant’s onsite documents, review of the applcant's responses to the staff's questions, and interviews with the applicant’s personnel, the staff determines that the AMP elements identified above are consistent with the GALL Report. The staff’s evaluation of the "scope of program" and "detection of aging effects" elements that will be enhanced will be documented in the staff’s SER Section 3.0.3.2.13.

3.2.12 LRA AMP B.1.40, “Water Chemistry – Closed Cooling Water”

In the LRA, the applicant stated that the Water Chemistry – Closed Cooling Water Program is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.M21, “Closed-Cycle Cooling Water System.”

During the audits, the staff verified that certain elements of the Water Chemistry – Closed Cooling Water Program are consistent with the corresponding elements in the XI.M21 AMP in the GALL Report. To verify the applicant’s claim of consistency, the staff reviewed the applicant’s onsite documentation supporting the applicant’s conclusion that the program element “corrective actions” is consistent with the corresponding element in the GALL AMP. In addition, the staff interviewed the applicant’s license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.15	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Water Chemistry Control – Closed Cooling Water Program	Rev. 2
NUREG-1801, XI.M21	Closed-Cycle Cooling Water System	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 1
0-CY-2510	Closed Cooling Water Chemistry Specifications and Frequencies	Rev. 3
0-CY-2515	Adding Chemicals to Closed Cooling Systems	Rev. 4

In comparing the elements in the applicant's AMP with GALL AMP XI.M21, the staff identified an area in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's request and the applicant's response are provided below.

Audit Item 94:

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.

Applicant's Response (Audit Item 94):

> 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.

Staff's Findings

Based on its review of the applicant's onsite documents, review of the applicant's response to the staff's question, and interviews with the applicant's personnel, the staff determines that the applicant's AMP element identified above is consistent with the GALL Report. The staff's evaluation of the "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" elements that will be enhanced and the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" elements to which the applicant has taken exception will be documented in the staff's SER Section 3.0.3.2.16.

3.2.13 LRA AMP B.1.41, "Water Chemistry Control – Primary and Secondary"

In the LRA, the applicant stated that the Water Chemistry Control – Primary and Secondary Program is an existing program that is consistent, with enhancements, with GALL AMP XI.M2, "Water Chemistry."

During the audits, the staff verified that certain elements of the Water Chemistry Control – Primary and Secondary Program are consistent with the corresponding elements in the XI.M2 AMP in the GALL Report. To verify the applicant's claim of consistency, the staff reviewed the applicant's onsite documentation supporting the applicant's conclusion that the program elements "scope of program," "preventive actions," "detection of aging effects," and "monitoring and trending" are consistent with the corresponding elements in the GALL AMP. In addition, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.14	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Water Chemistry Control – Primary and Secondary Program	Rev. 2
NUREG-1801, XI.M2	Water Chemistry	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 0
0-CY-2410	Secondary Chemistry Specifications	Rev. 5
0-CY-2310	Reactor Coolant System Specifications and Frequencies	Rev. 4
0-CY-1500	Chemistry Sampling Locations	Rev. 3
0-CY-1410	Laboratory Quality Compliance	Rev. 3
2-CY-2625	General Plant Systems Specifications and Frequencies	Rev. 7
3-CY-2625	General Plant Systems Specifications and Frequencies	Rev. 5
QA-02-2005-IP-1	Audit Report 2005	
QA-02-2006-IP-1	Audit Report 2006	

In comparing the elements in the applicant's AMP with GALL AMP XI.M2, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

<u>Audit Item 98</u>:

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 impacts the effectiveness of the AMP to manage aging effects.

<u>Applicant's Response (Audit Item 98)</u>:

> The Revision 4 changes to TR-1 05714 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.

Audit Item 99:

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?

Applicant's Response (Audit Item 99):

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.

Audit Item 100:

The LRA Section B.1.41, under Operating Experience, states that a QA audit of the primary and secondary plant chemistry program was conducted in August 2003 and this audit noted that monitoring and processing requirements for primary and secondary water chemistry complied with both IP2 and IP3 technical specifications, implementing procedures, and the IP3 Technical Requirements Manual (TRM).

(a) Why is there no statement about compliance with IP2 Technical Requirements Manual?

(b) The specific QA audit described above was in August 2003. How frequently are these QA audits performed?

Applicant's Response (Audit Item 100):

a) While chemistry requirements are currently included in the IP2 Technical Requirements Manual, the QA audit in August 2003 was performed during the improved technical specification project and updating the TRM for both units. At the time of the audit, the IP2 TRM was not updated with chemistry requirements.

b) QA audits of the chemistry department are performed every 2 years. An additional audit was performed in 2006 to adjust the two year cycle to even number years for scheduling purposes. Both 2005 and 2006 audit reports were provided during the audit.

Staff's Findings

Based on its review of the applicant's onsite documents, review of the applicant's responses to the staff's questions, and interviews with the applicant's personnel, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report. The staff's evaluation of the "parameters monitored or inspected" and "acceptance criteria" elements that will be enhanced will be documented in the staff's SER Section 3.0.3.2.17.

4 AGING MANAGEMENT REVIEWS

This section documents the staff's verification of the applicant's AMR.

The AMRs in the IP2 and IP3 LRA fall into three broad categories: (1) AMR results that are consistent with the GALL Report (i.e., those that the GALL Report concludes are adequate to manage aging of the components referenced in the GALL Report), (2) those for which the GALL Report concludes that aging management is adequate, but further evaluation is recommended for certain aspects of the aging management process, and (3) AMR results that are not consistent with or not addressed in the GALL Report.

The LRA presents numerous tables in LRA Chapter 3, labeled as Table 3.x.2.y-IPu (referred to as "Table 2"), where:

"3" indicates the LRA section number,
"x" indicates the table number from NUREG-1801, Volume 1,
"2" indicates that this is the second table type in Section 3.x,
"y" indicates the system table number, and
"IPu" indicates the unit, as necessary (IP2 or IP3). If a table encompasses both units (e.g., as with structures), this number is omitted.

Each LRA Table 3.x.2.y, that documents the AMR results for IP2 and IP3, contains information concerning whether or not the AMRs identified by the applicant align with the GALL Report AMRs. For a given AMR in a Table 2, the staff reviewed the intended function, material, environment, aging effect requiring management (AERM), and AMP combination for a particular system component type. Item numbers in column seven of the LRA, "NUREG-1801 Vol. 2

Item," correlate to an AMR combination as identified in the GALL Report. The staff conducted onsite audits to verify these correlations. A blank in column seven indicates that the applicant was unable to identify an appropriate correlation in the GALL Report. The staff also conducted a technical review of combinations not consistent with the GALL Report.

During the audits, the staff examined the applicant's justifications to verify that the applicant's activities and programs will adequately manage the effects of aging on SCs. The staff also conducted detailed discussions and interviews with the applicant's license renewal project personnel and others with technical expertise relevant to aging management.

During the audits, the staff verified the applicant's results for those AMRs that it claimed are consistent with the GALL Report, i.e., those that have Notes A through E.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the applicant's AMP is consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions. The staff's evaluation of the exceptions to the GALL Report AMP, if such exceptions exist, will be documented in the SER.

Note C indicates that the component for the AMR line item, although different from the GALL Report components, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified in the GALL Report a different component with the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from the GALL Report components, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the credited AMP would manage the aging effect consistently with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

The staff's audit results and review findings for AMR results identified by the applicant as consistent with the GALL Report will be documented in SER Sections 3.1.2.1, 3.2.2.1, 3.3.2.1, 3.4.2.1, 3.5.2.1, and 3.6.2.1.

For AMR results identified by the applicant that require further evaluation, the staff's evaluation will be documented in SER Sections 3.1.2.2, 3.2.2.2, 3.3.2.2, 3.4.2.2, 3.5.2.2, and 3.6.2.2. For AMR results identified by the applicant as not consistent with or addressed in the GALL Report, the staff's evaluation will be documented in SER Sections 3.1.2.3, 3.2.2.3, 3.3.2.3, 3.4.2.3, 3.5.2.3, and 3.6.2.3,

Below is a listing of the documents that the staff reviewed during the audits.

Document	Title
IP-RPT-06-LRD02	Aging Management Program Evaluation Results
IP-RPT-06-LRD05	Operating Experience Review Results
IP-RPT-06-LRD06	Aging Management Review Summary (AMRS)
IP-RPT-06-AMM01	Aging Management Review of the Containment Spray Systems
IP-RPT-06-AMM02	AMR of the Containment Isolation Systems
IP-RPT-06-AMM03	AMR of the Safety Injection Systems
IP-RPT-06-AMM04	AMR of the City Water System
IP-RPT-06-AMM05	AMR of the Residual Heat Removal Systems
IP-RRT-06-AMM06	AMR of the Unit 2 Primary Makeup Water System
IP-RPT-06-AMM07	AMR of the Chemical and Volume Control Systems
IP-RPT-06-AMM08	AMR of the Plant Drains
IP-RPT-06-AMM09	AMR of the Appendix R Fire Protection
IP-RPT-06-AMM10	AMR of the Nitrogen Systems
IP-RPT-06-AMM11	AMR of the Spent Fuel Pool Cooling Systems
IP-RPT-06-AMM12	AMR of the Service Water Systems
IP-RPT-06-AMM13	AMR of the Component Cooling Water Systems
IP-RPT-06-AMM14	AMR of the Compressed Air Systems
IP-RPT-06-AMM15	AMR of the Heating, Ventilation and Air Conditioning Systems
IP-RPT-06-AMM16	AMR of the Fire Protection – Water Systems
IP-RPT-06-AMM17	AMR of the Emergency Diesel Generator Systems
IP-RPT-06-AMM18	AMR of the Security Generators
IP-RPT-06-AMM19	AMR of the Fire Protection – CO_2, Halon and RCP Oil Collection Systems
IP-RPT-06-AMM20	AMR of the IP2 SBO and Appendix R Diesel Generator
IP-RPT-06-AMM21	AMR of the Fuel Oil Systems
IP-RPT-06-AMM22	AMR of the Unit 3 Appendix R Diesel Generator
IP-RPT-06-AMM23	AMR of the Main Steam Systems
IP-RPT-06-AMM24	AMR of the Auxiliary Feedwater Systems
IP-RPT-06-AMM25	AMR of the Blowdown Systems
IP-RPT-06-AMM26	AMR of the Containment Penetrations
IP-RPT-06-AMM27	AMR of the Main Feedwater System
IP-RPT-06-AMM28	AMR of the Containment Cooling and Filtration Systems
IP-RPT-06-AMM29	AMR of the Control Room Heating, Ventilation and Air Conditioning

Document	Title
	Systems
IP-RPT-06-AMM30	AMR of the Nonsafety-Related Systems and Components Affecting Safety-Related Systems
IP-RPT-06-AMM31	AMR of the Reactor Vessel
IP-RPT-06-AMM32	AMR of the Reactor Vessel Internals
IP-RPT-06-AMM33	AMR of the Reactor Coolant System Pressure Boundary
IP-RPT-06-AMM34	AMR of the Steam Generators
IP-RPT-06-AME01	Electrical Screening and Aging Management Review
IP-RPT-06-AMC01	Containment Building
IP-RPT-06-AMC02	Water Control Structures
IP-RPT-06-AMC03	Turbine Building, Auxiliary Building and Other Structures
IP-RPT-06-AMC04	Bulk Commodities
	Plant equipment drawing #9321-F-1468-5 (IP2)
	Plant equipment drawing #9321-F-14683-2 (IP3)

During the audits, the staff requested additional information of the applicant to assist in the staff's audit efforts. The staff's questions and the applicant's responses are documented in a letter from Entergy dated December 18, 2007, in Attachment 4 (ADAMS Accession No. ML073650195). The staff's evaluation of the applicant's responses will be documented in SER Sections 3.1 through 3.6 as appropriate.

5 AGING TIME LIMITED AGING ANALYSES AUDIT RESULTS

During the audits, the staff audited supporting documents for those TLAAs that are related to metal fatigue. The staff's evaluation of the metal fatigue TLAAs will be documented in SER Section 4.3. All other plant-specific TLAAs identified in the LRA were reviewed at NRC headquarters by other members of the staff. The staff's evaluation of these TLAAs will be documented in SER Sections 4.2 and 4.4 through 4.7.

Below is a list of the documents that were reviewed by the staff during the audits.

Document	Title	Revision or Date
IP-RPT-06-LRD03	TLAA and Exemption Evaluation Results	Revision 0
IP-RPT-06-LRD04	TLAA - Mechanical Fatigue	Revision 0
WCAP-12639	Westinghouse Owners Group Pressurizer Surge Line Thermal Stratification Generic Detailed Analysis	
Procedure 2-POP-1.1	Plant Heatup from Cold Shutdown Condition	Revision 79
IP-DEM-01-008MC	IP3 Pressurizer Surge line Stratification – WR-96-6280-02	
WCAP-16156-P	Indian Point Nuclear Generating Unit No. 2, Stretch Power Uprate NSSS Engineering Report	February 2004
WCAP-16211-P	Power Uprate Project, Indian Point Unit 3 Power Plant, NSSS Engineering Report	June 2004

Document	Title	Revision or Date
WCAP-12191	Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Final Report for IP2	Revision 2, July 1992
WCAP-12191	Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Report for Indian Point Unit 2, Addendum 1	Revision 3, September 2003
CN-RCDA-03-64	Indian Point Unit 2 Stretch Power Uprate Reactor Vessel Evaluation	
CN-RCDA-03-75	Indian Point Unit 3 Stretch Power Uprate Reactor Vessel Structural Evaluation	
IPEC calculation CN-SMT-00-95	IP2 Loop 3-10 inch Accumulator Nozzle Fatigue Evaluation without Thermal Sleeve	Revision 1
2-PT-2Y15	Thermal Cycle Monitoring Program	April 8, 2004
COR-06-00178	Assessment of IP2 Steam Generator Feedwater Nozzle to Shell Weld Indication	May 5, 2006
IPEC Calculation R-4147-00-1	Reactor Vessel Tensioning Optimization Stress Report IP2 and IP3	Revision 0
Westinghouse letter, SE&PT-SSAD-7712	Letter from M.A. Gray and J.R. Lunn to C.B. Bond, Indian Point 2 Piping Usage Factors	June 1988
IP2 Calculation WNET-108	Consolidated Edison Company Pressurizer Stress Report	Revision 0, April 7, 1969
IPEC calculation CN-SMT-00-95	IP2 Loop 3 -10-inch Accumulator Nozzle Fatigue Evaluation Without Thermal Sleeve	Revision 1, August 24, 2001
WCAP-15859	Addendum to Analytical Report for the Indian Point Vessel Unit No. 3 - Mini-Uprate Evaluation	
WCAP-16209-P		Rev. 0
WCAP-16169-P		Rev. 0
CENC-1110	Reactor Pressure Vessel Stress Report	
CENC-1122	Reactor Pressure Vessel Stress Report	

During the audits, the staff requested additional information of the applicant to assist in the staff's audit efforts. The staff's questions and the applicant's responses are documented in a letter from Entergy dated March 24, 2008, in Attachments 2 and 4 (ADAMS Accession No. ML081070255). The staff's evaluation of the applicant's responses will be documented in SER Section 4.3.

APPENDIX A

Personnel Contacted or in Attendance During NRC Audits

NRC Project Team Members

Kimberly Green, Project Manager, Division of License Renewal (DLR)
James Davis, Sr. Materials Engineer, DLR
Peter Wen, Mechanical Engineer, DLR
Surinder Aurora, Mechanical Engineer, DLR
Duc Nguyen, Electrical Engineer, DLR
Qi Gan, General Engineer, DLR
On Yee, General Engineer, DLR
Yeon-Ki Chung, Engineer, Foreign Assignee to NRC
Richard Morante, Consultant, Brookhaven National Laboratory (BNL)
Joe Braverman, Consultant, BNL
Mano Subudhi, Consultant, BNL
Ken Sullivan, Consultant, BNL

NRC Project Team Support

Kenneth Chang, Branch Chief, DLR
Rani Franovich, Branch Chief, DLR
Barbara Reese, Admistrative support, BNL

Applicant Personnel

Dan Wilson, Chemistry Superintendent, Indain Point (IP)
Don Croulet, Superintendent, IP
Robert Christman, Training Manager, IP
Kevin O'Kane, Manager, IP
Joe Perrotta, Quality Assurance Manager, IP
Joe Bahr, Admin. Services Superintendent, IP
Mike Stroud, License Renewal, Entergy Nuclear Operations, Inc (Entergy)
Alan Cox, License Renewal, Entergy
David Lach, License Renewal, Entergy
Tom Orlando, Engineering Director, IP
Bob Walpole, Licensing Manager, IP
John Curry, Project Manager, IP
Don Mayer, Director Unit 1, IP
John Donnelly, Manager, Corrective Action, IP
Bill Josiger, License Renewal, IP
Reza Ahrabli, License Renewal, Entergy
Don Fronabarger, License Renewal, Entergy
Randy Smith, License Renewal, Entergy
John Dinelli, Operations Manager, IP

Frank Inzirillo, Assistant to Site VP, IP
Mike Tesoriero, Supervisor, Engineering, IP
Jill Brochu, License Renewal, Entergy
Roger Rucker, License Renewal, Entergy
Rich Burroni, Manager, IP
Craig Phillipe, HR Manager, IP
Ted Ivy, License Renewal, Entergy
Bob Dolansky, Engineer, IP
Richard Drake, Design Engineering, IP
Charles Caputo, License Renewal, Entergy
Donna Tyner, Licensing, IP
Mel Garofalo, Quality Assurance, IP
George Dahl, Licensing, IP
Ron Finnin, License Renewal, Entergy
Nelson Azevedo, Code Programs, IP
Tom McCaffrey, Design Engineer, IP
Walter Wittich, Progrmas Engineering, IP
Garry Young, License Renewal, Entergy
Steve Prussman, Licensing, IP
Charlie Jackson, License Renewal, Entergy
Steven Verrochi, System Engineering, IP
Paul Studley, Operations Manager, IP