APPENDIX B

AGING MANAGEMENT PROGRAMS AND ACTIVITIES

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B.0 INTRODUCTION

B.0.1 OVERVIEW

The aging management review results for the integrated plant assessment of Indian Point Energy Center (IPEC) are presented in Sections 3.1 through 3.6 of this application. The programs credited in the integrated plant assessment for managing aging effects are described in this appendix.

Each aging management program described in this appendix has ten elements in accordance with the guidance in NUREG-1800 (Reference B.2-1) Appendix A.1, "Aging Management Review - Generic," Table A.1-1, "Elements of an Aging Management Program for License Renewal." For aging management programs that are comparable to the programs described in Sections X and XI of NUREG-1801 (Reference B.2-2), *Generic Aging Lessons Learned (GALL) Report*, the ten elements have been compared to the elements of the NUREG-1801 program. For plant-specific programs which do not correlate with NUREG-1801, the ten elements are addressed in the program evaluation.

B.0.2 FORMAT OF PRESENTATION

For those aging management programs that are comparable to the programs described in Sections X and XI of NUREG-1801, the program discussion is presented in the following format.

- **Program Description**: abstract of the overall program.
- **NUREG-1801 Consistency**: summary of the degree of consistency between the IPEC program and the corresponding NUREG-1801 program, when applicable (i.e., degree of similarity, etc.).
- **Exceptions to NUREG-1801**: exceptions to the NUREG-1801 program, including a justification for the exceptions (when applicable).
- **Enhancements**: future program enhancements with a proposed schedule for their completion (when applicable), including additional program features to manage aging effects not addressed by the NUREG-1801 program.
- **Operating Experience**: discussion of operating experience information specific to the program.
- **Conclusion**: statement assures that the program is effective, or will be effective, once implemented with necessary enhancements.

For plant-specific programs, the program description, ten elements, enhancements, and conclusion are presented.

B.0.3 CORRECTIVE ACTIONS, CONFIRMATION PROCESS AND ADMINISTRATIVE CONTROLS

Three attributes common to all aging management programs are corrective actions, confirmation process and administrative controls. Discussion of these attributes is presented below. Corrective actions have program-specific details which are included in the descriptions of the individual programs in this report, but further discussion of the confirmation process and administrative controls is not necessary and is not included in the descriptions of the individual programs.

Corrective Actions

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. Conditions adverse to quality, such as failures, malfunctions, deviations, defective material and equipment, and nonconformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the nonconformance is determined and that corrective action is taken to preclude recurrence. In addition, the root cause of the significant condition adverse to quality and the corrective action implemented are documented and reported to appropriate levels of management. The corrective action controls of the Entergy (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities during the period of extended operation.

Confirmation Process

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The Entergy Quality Assurance Program applies to safety-related structures and components. Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished per the existing site corrective action program and document control program. The confirmation process is part of the corrective action program and includes

- reviews to assure that proposed actions are adequate,
- tracking and reporting of open corrective actions, and
- review of corrective action effectiveness.

Any follow-up inspection required by the confirmation process is documented in accordance with the corrective action program. The corrective action program constitutes the confirmation process for aging management programs and activities. The IPEC confirmation process is consistent with NUREG-1801.

Administrative Controls

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The Entergy Quality Assurance Program applies to safety-related structures and components. Administrative (document) control for both safety-related and nonsafety-related structures and components is accomplished per the existing document control program. The IPEC administrative controls are consistent with NUREG-1801.

B.0.4 OPERATING EXPERIENCE

Operating experience for the programs and activities credited with managing the effects of aging was reviewed. The operating experience review included a review of corrective actions resulting in program enhancements. For inspection programs, reports of recent inspections, examinations, or tests were reviewed to determine if aging effects have been identified on applicable components. For monitoring programs, reports of sample results were reviewed to determine if parameters are being maintained as required by the program. Also, program owners contributed observations indicative of program success or weakness and identified applicable self-assessments, QA audits, peer evaluations, and NRC reviews.

Site procedures require reviews of site and relevant industry OE as the site continues operation through the license renewal period.

B.0.5 AGING MANAGEMENT PROGRAMS

Aging management programs are described in the sections listed below (Table B-1). Programs are identified as either existing or new. The programs are compared to programs described in NUREG-1801 or they are plant-specific. The correlation between NUREG-1801 programs and IPEC programs is shown in Table B-2.

Table B-1
Aging Management Programs

Aboveground Steel Tanks	B.1.1	existing
Bolting Integrity	B.1.2	existing
Boraflex Monitoring	B.1.3	existing
Boral Surveillance	B.1.4	existing
Boric Acid Corrosion Prevention	B.1.5	existing
Buried Piping and Tanks Inspection	B.1.6	new
Containment Leak Rate	B.1.7	existing

Table B-1
Aging Management Programs (Continued)

Containment Inservice Inspection	B.1.8	existing
Diesel Fuel Monitoring	B.1.9	existing
Environmental Qualification (EQ) of Electric Components	B.1.10	existing
External Surfaces Monitoring	B.1.11	existing
Fatigue Monitoring	B.1.12	existing
Fire Protection	B.1.13	existing
Fire Water System	B.1.14	existing
Flow-Accelerated Corrosion	B.1.15	existing
Flux Thimble Tube Inspection	B.1.16	existing
Heat Exchanger Monitoring	B.1.17	existing
Inservice Inspection (ISI)	B.1.18	existing
Masonry Wall	B.1.19	existing
Metal-Enclosed Bus Inspection	B.1.20	existing
Nickel Alloy Inspection	B.1.21	existing
Non-EQ Bolted Cable Connections	B.1.22	new
Non-EQ Inaccessible Medium-Voltage Cable	B.1.23	new
Non-EQ Instrumentation Circuits Test Review	B.1.24	new
Non-EQ Insulated Cables and Connections	B.1.25	new
Oil Analysis	B.1.26	existing
One-Time Inspection	B.1.27	new
One-Time Inspection – Small Bore Piping	B.1.28	new
Periodic Surveillance and Preventive Maintenance	B.1.29	existing

Table B-1
Aging Management Programs (Continued)

Reactor Head Closure Studs	B.1.30	existing
Reactor Vessel Head Penetration Inspection	B.1.31	existing
Reactor Vessel Surveillance	B.1.32	existing
Selective Leaching	B.1.33	new
Service Water Integrity	B.1.34	existing
Steam Generator Integrity	B.1.35	existing
Structures Monitoring	B.1.36	existing
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	B.1.37	new
Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	B.1.38	new
Water Chemistry Control – Auxiliary Systems	B.1.39	existing
Water Chemistry Control – Closed Cooling Water	B.1.40	existing
Water Chemistry Control – Primary and Secondary	B.1.41	existing

B.0.6 CORRELATION WITH NUREG-1801 AGING MANAGEMENT PROGRAMS

The correlation between NUREG-1801 programs and IPEC programs is shown below. For the IPEC programs, links to appropriate sections of this appendix are provided.

Table B-2
IPEC AMP Correlation with NUREG-1801 Programs

NUREG-1801 Number	NUREG-1801 Program	IPEC Program
X.E1	Environmental Qualification (EQ) of Electric Components	Environmental Qualification (EQ) of Electric Components [B.1.10]
X.M1	Metal Fatigue of Reactor Coolant Pressure Boundary	Fatigue Monitoring [B.1.12]
X.S1	Concrete Containment Tendon Prestress	IPEC does not have pre-stressed tendons in the containment structures. The NUREG-1801 program does not apply.
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	See plant-specific Inservice Inspection (ISI) [B.1.18]
XI.M2	Water Chemistry	Water Chemistry Control – Primary and Secondary [B.1.41]
XI.M3	Reactor Head Closure Studs	Reactor Head Closure Studs [B.1.30]
XI.M4	BWR Vessel ID Attachment Welds	IPEC units are PWRs. The NUREG-1801 program does not apply.
XI.M5	BWR Feedwater Nozzle	IPEC units are PWRs. The NUREG-1801 program does not apply.
XI.M6	BWR Control Rod Drive Return Line Nozzle	IPEC units are PWRs. The NUREG-1801 program does not apply.
XI.M7	BWR Stress Corrosion Cracking	IPEC units are PWRs. The NUREG-1801 program does not apply.
XI.M8	BWR Penetrations	IPEC units are PWRs. The NUREG-1801 program does not apply.

Table B-2
IPEC AMP Correlation with NUREG-1801 Programs (Continued)

NUREG-1801 Number	NUREG-1801 Program	IPEC Program
XI.M9	BWR Vessel Internals	IPEC units are PWRs. The NUREG-1801 program does not apply.
XI.M10	Boric Acid Corrosion	Boric Acid Corrosion Prevention [B.1.5]
XI.M11A	Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	Reactor Vessel Head Penetration Inspection [B.1.31]
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) [B.1.37]
XI.M13	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) [B.1.38]
XI.M14	Loose Part Monitoring	Not credited for aging management.
XI.M15	Neutron Noise Monitoring	Not credited for aging management.
XI.M16	PWR Vessel Internals	In accordance with NUREG-1801, guidance for the aging management of PWR vessel internals is provided in AMR line items. Refer to Appendix A, Sections A.2.1.41 and A.3.1.41 for reactor vessel internals aging management activities.
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion [B.1.15]
XI.M18	Bolting Integrity	Bolting Integrity [B.1.2]
XI.M19	Steam Generator Tube Integrity	Steam Generator Integrity [B.1.35]
XI.M20	Open-Cycle Cooling Water System	Service Water Integrity [B.1.34]

Table B-2
IPEC AMP Correlation with NUREG-1801 Programs (Continued)

NUREG-1801 Number	NUREG-1801 Program	IPEC Program
XI.M21	Closed-Cycle Cooling Water System	Water Chemistry Control – Closed Cooling Water [B.1.40]
XI.M22	Boraflex Monitoring	Boraflex Monitoring [B.1.3]
XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Structures Monitoring Program [B.1.36] and the Periodic Surveillance and Preventive Maintenance Program [B.1.29] manage the effects of aging for crane components. See aging management review results in Section 3.5 tables.
XI.M24	Compressed Air Monitoring	Not used. Programs identified in Section 3.3.2.1.4 manage the effects of aging for compressed air system components.
XI.M25	BWR Reactor Water Cleanup System	IPEC units are PWRs. The NUREG-1801 program does not apply.
XI.M26	Fire Protection	Fire Protection [B.1.13]
XI.M27	Fire Water System	Fire Water System [B.1.14]
XI.M28	Buried Piping and Tanks Surveillance	Not credited for aging management. The Buried Piping and Tanks Inspection Program [B.1.6] manages the effects of aging on buried piping and tanks.
XI.M29	Aboveground Steel Tanks	Aboveground Steel Tanks [B.1.1]
XI.M30	Fuel Oil Chemistry	Diesel Fuel Monitoring [B.1.9]
XI.M31	Reactor Vessel Surveillance	Reactor Vessel Surveillance [B.1.32]
XI.M32	One-Time Inspection	One-Time Inspection [B.1.27]
XI.M33	Selective Leaching of Materials	Selective Leaching [B.1.33]

Table B-2
IPEC AMP Correlation with NUREG-1801 Programs (Continued)

NUREG-1801 Number	NUREG-1801 Program	IPEC Program
XI.M34	Buried Piping and Tanks Inspection	Buried Piping and Tanks Inspection [B.1.6]
XI.M35	One-time Inspection of ASME Code Class 1 Small-Bore Piping	One-Time Inspection – Small Bore Piping [B.1.28]
XI.M36	External Surfaces Monitoring	External Surfaces Monitoring [B.1.11]
XI.M37	Flux Thimble Tube Inspection	Flux Thimble Tube Inspection [B.1.16]
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	The External Surfaces Monitoring Program [B.1.11] or the Periodic Surveillance and Preventive Maintenance Program [B.1.29] manage the effects of aging on internal surfaces of piping and ducting components.
XI.M39	Lubricating Oil Analysis	Oil Analysis [B.1.26]
XI.E1	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Non-EQ Insulated Cables and Connections [B.1.25]
XI.E2	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Non-EQ Instrumentation Circuits Test Review [B.1.24]
XI.E3	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Non-EQ Inaccessible Medium-Voltage Cable [B.1.23]
XI.E4	Metal Enclosed Bus	Metal-Enclosed Bus Inspection [B.1.20]

Table B-2
IPEC AMP Correlation with NUREG-1801 Programs (Continued)

NUREG-1801 Number	NUREG-1801 Program	IPEC Program
XI.E5	Fuse Holders	Not credited. Refer to Table 3.6.1, Item 3.6.1-6.
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	See Non-EQ Bolted Cable Connections [B.1.22] for an alternative.
XI.S1	ASME Section XI, Subsection IWE	See plant-specific Containment Inservice Inspection (CII) [B.1.8]
XI.S2	ASME Section XI, Subsection IWL	See plant-specific Containment Inservice Inspection (CII) [B.1.8]
XI.S3	ASME Section XI, Subsection IWF	See plant-specific Inservice Inspection (ISI) [B.1.18]
XI.S4	10 CFR 50, Appendix J	Containment Leak Rate [B.1.7]
XI.S5	Masonry Wall Program	Masonry Wall [B.1.19]
XI.S6	Structures Monitoring Program	Structures Monitoring [B.1.36]
XI.S7	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	This program is not credited for aging management. The Structures Monitoring Program manages the effects of aging on the water control structures at IPEC.
XI.S8	Protective Coating Monitoring and Maintenance Program	This program is not credited for aging management. Containment Inservice Inspection Program manages the effects of aging on the containment liner at IPEC.
Plant-Specific Programs		
NA	Plant-specific program	Boral Surveillance [B.1.4]
NA	Plant-specific program	Containment Inservice Inspection (CII) [B.1.8]

Table B-2
IPEC AMP Correlation with NUREG-1801 Programs (Continued)

NUREG-1801 Number	NUREG-1801 Program	IPEC Program
NA	Plant-specific program	Heat Exchanger Monitoring [B.1.17]
NA	Plant-specific program	Inservice Inspection (ISI) [B.1.18]
NA	Plant-specific program	Nickel Alloy Inspection [B.1.21]
NA	Plant-specific program	Non-EQ Bolted Cable Connections [B.1.22]
NA	Plant-specific program	Periodic Surveillance and Preventive Maintenance [B.1.29]
NA	Plant-specific program	Water Chemistry Control – Auxiliary Systems [B.1.39]

Table B-3 indicates the consistency of IPEC programs with NUREG-1801 programs.

Table B-3
IPEC Program Consistency with NUREG-1801

Program Name	Plant Specific	NUREG-1801 Comparison		
		Programs Consistent with NUREG-1801	Programs with Enhancements	Programs with Exceptions to NUREG-1801
Aboveground Steel Tanks		X	X	
Bolting Integrity		X	X	
Boraflex Monitoring				X
Boral Surveillance	X			
Boric Acid Corrosion Prevention		X		
Buried Piping and Tanks Inspection		X		
Containment Leak Rate		X		
Containment Inservice Inspection	X			
Diesel Fuel Monitoring			X	X
Environmental Qualification (EQ) of Electric Components		X		
External Surfaces Monitoring		X	X	
Fatigue Monitoring			X	X
Fire Protection			X	X
Fire Water System			X	X

Table B-3
IPEC Program Consistency with NUREG-1801 (Continued)

Program Name	Plant Specific	NUREG-1801 Comparison		
		Programs Consistent with NUREG-1801	Programs with Enhancements	Programs with Exceptions to NUREG-1801
Flow-Accelerated Corrosion		X		
Flux Thimble Tube Inspection		X	X	
Heat Exchanger Monitoring	X			
Inservice Inspection (ISI)	X			
Masonry Wall		X	X	
Metal-Enclosed Bus Inspection			X	X
Nickel Alloy Inspection	X			
Non-EQ Bolted Cable Connections	X			
Non-EQ Inaccessible Medium-Voltage Cable		X		
Non-EQ Instrumentation Circuits Test Review		X		
Non-EQ Insulated Cables and Connections		X		
Oil Analysis			X	X
One-Time Inspection		X		
One-Time Inspection – Small Bore Piping		X		

Table B-3
IPEC Program Consistency with NUREG-1801 (Continued)

Program Name	Plant Specific	NUREG-1801 Comparison		
		Programs Consistent with NUREG-1801	Programs with Enhancements	Programs with Exceptions to NUREG-1801
Periodic Surveillance and Preventive Maintenance	X			
Reactor Head Closure Studs		X		
Reactor Vessel Head Penetration Inspection		X		
Reactor Vessel Surveillance		X	X	
Selective Leaching		X		
Service Water Integrity		X		
Steam Generator Integrity		X	X	
Structures Monitoring		X	X	
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)		X		
Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)		X		
Water Chemistry Control – Auxiliary Systems	X			
Water Chemistry Control – Closed Cooling Water			X	X

Table B-3
IPEC Program Consistency with NUREG-1801 (Continued)

Program Name	Plant Specific	NUREG-1801 Comparison		
		Programs Consistent with NUREG-1801	Programs with Enhancements	Programs with Exceptions to NUREG-1801
Water Chemistry Control – Primary and Secondary		X	X	

B.1 AGING MANAGEMENT PROGRAMS AND ACTIVITIES

B.1.1 ABOVEGROUND STEEL TANKS

Program Description

The Aboveground Steel Tanks Program is an existing program that manages loss of material from external surfaces of aboveground carbon steel tanks by periodic visual inspection of external surfaces and thickness measurement of locations that are inaccessible for external visual inspection.

NUREG-1801 Consistency

The Aboveground Steel Tanks Program is consistent with the program described in NUREG-1801, Section XI.M29, Aboveground Steel Tanks with enhancements.

Exceptions to NUREG-1801

None

Enhancements

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

Attributes Affected	Enhancement
4. Detection of Aging Effects 6. Acceptance Criteria	Revise applicable procedures to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank (IP2), and fire water tanks, once during the first ten years of the period of extended operation.
5. Monitoring and Trending	Revise applicable procedures to require trending of thickness measurements when material loss is detected.

Operating Experience

Visual inspections detected corrosion on the top of the IP3 condensate storage tank in 2003 and 2005 and on the IP2 condensate storage tank in 2004. Corrective actions were issued to clean and repaint the surfaces, which will prevent recurrence.

Visual inspections of the external surfaces of the gas turbine fuel storage tanks in December 2006 indicated no loss of material due to corrosion.

Thickness measurements of the gas turbine fuel storage tanks in April 2002 found pitting up to 60% through-wall, with no loss of intended function. This was repaired with a weld overlay.

Internal inspections of the IP2 fire water storage tank and the training center fire water storage tank in 2003 detected failure of the coating in several places, but no appreciable metal loss was identified. Corrective actions were issued to repair the coating.

Identification of degradation and performance of corrective action prior to loss of intended function provide assurance that the program is effective for managing aging effects for passive components.

Conclusion

The Aboveground Steel Tanks Program has been effective at managing aging effects. The Aboveground Steel Tanks Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.2 BOLTING INTEGRITY

Program Description

The Bolting Integrity Program is an existing program that relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, industry recommendations, and Electric Power Research Institute (EPRI) NP-5769, with the exceptions noted in NUREG-1339 for safety-related bolting. The program relies on industry recommendations for comprehensive bolting maintenance, as delineated in EPRI TR-104213 for pressure retaining bolting and structural bolting.

The program applies to bolting and torquing practices of safety- and nonsafety-related bolting for pressure retaining components, NSSS component supports, and structural joints. The program addresses all bolting regardless of size except reactor head closure studs, which are addressed by the Reactor Head Closure Studs Program [B.1.30]. The program includes periodic inspection of closure bolting for signs of leakage that may be due to crack initiation, loss of preload, or loss of material due to corrosion. The program also includes preventive measures to preclude or minimize loss of preload and cracking.

NUREG-1801 Consistency

The Bolting Integrity Program is consistent with the program described in NUREG-1801, Section XI.M18, Bolting Integrity with one enhancement.

Exceptions to NUREG-1801

None

Enhancements

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

Attributes Affected	Enhancements
2. Preventive Actions	Revise applicable procedures to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and to clarify the prohibition on use of lubricants containing MoS_2 for bolting.

Operating Experience

Visual inspections of bolted connections were documented during 2001 through 2005. Although corrosion products were found on some bolting materials, no situations were identified where loss of material had precluded the bolted connection from performing its intended function. Corrective actions were completed to ensure future integrity of the bolted connection. Identification of degradation and performance of corrective action prior to loss of intended function provide assurance that the program is effective for managing aging effects for passive components.

Conclusion

The Bolting Integrity Program has been effective at managing aging effects. The Bolting Integrity Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.3 BORAFLEX MONITORING

Program Description

The Boraflex Monitoring Program is an existing program that assures degradation of the Boraflex panels in the spent fuel racks does not compromise the criticality analysis in support of the design of the spent fuel storage racks. The program relies on (1) areal density testing, (2) use of a predictive computer code, and (3) determination of boron loss through correlation of silica levels in spent fuel water samples to assure that the required 5% subcriticality margin is maintained. Corrective actions are initiated if the test results find that the 5% subcriticality margin cannot be maintained because of current or projected Boraflex degradation.

This program applies to IP2 only since Boraflex is not used for criticality control of IP3 spent fuel.

NUREG-1801 Consistency

The Boraflex Monitoring Program is consistent with the program described in NUREG-1801, Section XI.M22, Boraflex Monitoring, with exceptions.

Exceptions to NUREG-1801

The Boraflex Monitoring Program is consistent with the program described in NUREG-1801, Section XI.M22, Boraflex Monitoring, with the following exceptions.

Attributes Affected	Exception
2. Preventive Actions	NUREG-1801 specifies measuring gap formation by blackness testing. The IPEC program specifies areal density measurements for boraflex degradation.[1]
4. Detection of Aging Effects	NUREG-1801 recommends blackness testing as a supplement to areal density measurements for determining gap formations. The IPEC program specifies areal density testing only.[1]

Exception Note

1. The NRC Staff, as documented in the SER for Oyster Creek, has accepted the position that areal density measurement in lieu of blackness testing is acceptable. Areal density testing provides a direct measurement of in-rack performance of Boraflex panels through measurement of gaps, erosion, and general thinning. Blackness testing provides only an indication of neutron absorber presence and does not quantitatively measure the Boron-10 areal density of neutron absorber in each rack. Therefore, areal density along with the monitoring of silica levels in the spent fuel pool provides adequate detection of boraflex degradation.

Enhancements

None

Operating Experience

Panels of Boraflex are used to maintain adequate subcriticality of the fuel in the spent fuel racks. Since Boraflex is susceptible to in-service degradation, a RACKLIFE model of the IP2 spent fuel pool was developed. Boron-10 areal density gage for evaluating racks (BADGER) testing was performed in February 2000, July 2003 and again in July 2006. The results confirmed the predictions of the RACKLIFE computer model, and provide evidence that the program is effective for managing change in material properties (reduction in neutron-absorbing capacity) for Boraflex neutron absorber panels.

Conclusion

The Boraflex Monitoring Program has been effective at managing aging effects. The Boraflex Monitoring Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.4 BORAL SURVEILLANCE

Program Description

The Boral Surveillance Program is an existing program that assures the Boral neutron absorbers in the spent fuel racks maintain the validity of the criticality analysis in support of the rack design. The program relies on representative coupon samples mounted in surveillance assemblies located in the spent fuel pool to monitor performance of the absorber material without disrupting the integrity of the storage system.

Surveillance assemblies are removed from the spent fuel pool on a prescribed schedule and physical and chemical properties are measured. From this data, the stability and integrity of the Boral in the storage cells are assessed.

This program applies to IP3 only since Boral is not used for criticality control of IP2 spent fuel.

Evaluation

1. **Scope of Program**

   The Boral Surveillance Program includes all boral in the IP3 spent fuel pool. The IP2 spent fuel pool design does not rely on Boral for criticality control.

2. **Preventive Actions**

   This is an inspection program and no actions are taken as part of this program to prevent or mitigate aging degradation.

3. **Parameters Monitored or Inspected**

   The program monitors changes in the following physical properties of the Boral material.

   - neutron attenuation
   - blister size, thickness, and location
   - dimensional measurements (length, width, shape, and thickness)
   - specific gravity and density

4. **Detection of Aging Effects**

   The program monitors representative coupon samples located in the spent fuel pool to determine the condition of the absorber material without disrupting the integrity of the storage system. At specified intervals, the program measures certain physical and chemical properties of removed sample coupons. From this data, the stability and integrity of the Boral in the storage cells are assessed.

5. Monitoring and Trending

Neutron attenuation tests are trended to ensure that slow degradation is not occurring. Observable loss in neutron attenuation ability, if any, is projected to determine when neutron attenuation may fall below acceptance criteria.

Size and weight measurements determine the extent of shrinkage or loss of material. This data is trended for indications of degradation.

Blister shape and size are recorded and trended to determine whether new blisters are forming, the rate of growth of existing blisters, and the rate of increase in blister thickness. As blister thickness increases, it may become necessary to evaluate whether potential fuel cell deformation is a risk due to blister growth.

6. Acceptance Criteria

Of the measurements to be performed on the Boral, the most important are neutron attenuation measurements and dimensional measurements. Acceptance criteria for these measurements are as follows.

- Neutron attenuation testing and B-10 areal density is equal to or greater than the B-10 gm/cm^2 nominal density assumed in the criticality analysis (0.02 g/cm^2)
- Blisters are unacceptable if blister size and shape projected to the next inspection may subsume the available space between the fuel assembly and the cell wall.

7. Corrective Action

When adverse trends are identified, engineering will determine the appropriate course of action, which is documented through the site corrective action program. Specific corrective actions will depend upon the nature of the adverse trend and may include reanalysis, modified surveillance frequencies or activities, or fuel relocation.

8. Confirmation Process

This attribute is discussed in Section B.0.3.

9. Administrative Controls

This attribute is discussed in Section B.0.3.

10. Operating Experience

Results of an inspection of coupon samples in 2002 showed no significant degradation of Boral material. A review of this program was performed in 2004 with respect to the Seabrook Part 21 issue on Boral coupon blistering (NRC21-031006 Part 21). As a result, the procedure for IP3 Boral examinations was revised to test the same full-length Boral sample during the next inspection (2007) as was tested during the last inspection (2002). This will allow direct measurement of blister growth and will determine if the Boral blisters have reached equilibrium.

The IPEC program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, operating experience assures that the Boral Surveillance Program will remain effective for managing loss of material of the Boral neutron absorber.

Conclusion

The Boral Surveillance Program has been effective at managing aging effects. The Boral Surveillance Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.5 BORIC ACID CORROSION PREVENTION

Program Description

The Boric Acid Corrosion Prevention Program is an existing program that relies on implementation of recommendations of NRC Generic Letter 88-05 to monitor the condition of components on which borated reactor water may leak. The program detects boric acid leakage by periodic visual inspection of systems containing borated water for deposits of boric acid crystals and the presence of moisture; and by inspection of adjacent structures, components, and supports for evidence of leakage. This program manages loss of material and loss of circuit continuity, as applicable. The program includes provisions for evaluation when leakage is discovered by other activities. Program improvements have been made as suggested in NRC Regulatory Issue Summary 2003-013.

NUREG-1801 Consistency

The Boric Acid Corrosion Prevention Program is consistent with the program described in NUREG-1801, Section XI.M10, Boric Acid Corrosion.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

Minor boron leakage was detected during inspections of the IP2 containment building in April 2005, November 2005, and May 2006. Boron leakage was detected in March 2005 during an inspection of reactor coolant boundary components at IP3 which may be subject to boric acid leakage and corrosion. Early detection of leakage precluded boric acid wastage of affected components and adjacent structures and components. Identification of degradation and corrective action prior to loss of intended function provide evidence that the program is effective for managing aging effects for passive components.

The Boric Acid Corrosion Prevention Program was enhanced to include recommendations of the Westinghouse Owner's Group WCAP-15988-NP "Generic Guidance to Best Practice 88-05 Boric Acid Inspection Program," EPRI Technical Report 1000975 "Boric Acid Corrosion Guidebook," and NRC Bulletin 2003-02 "Leakage from Reactor Coolant Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity." Ongoing process improvements through incorporation of lessons learned from industry operating experience provide assurance that the program will remain effective for managing aging effects for passive components.

Conclusion

The Boric Acid Corrosion Prevention Program has been effective at managing aging effects. The Boric Acid Corrosion Prevention Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.6 BURIED PIPING AND TANKS INSPECTION

Program Description

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

- Safety injection
- Service water
- Fire protection
- Fuel oil
- Security generator
- City water
- Plant drains
- Auxiliary feedwater

Of these systems, only the safety injection system contains radioactive fluids during normal operations. The safety injection system buried components are stainless steel. Stainless steel is used in the safety injection system for its corrosion resistance.

Prior to entering the period of extended operation, plant operating experience will be reviewed to verify that an inspection occurred within the past ten years. If an inspection did not occur, a focused inspection will be performed prior to the period of extended operation. A focused inspection will be performed within the first ten years of the period of extended operation, unless an opportunistic inspection occurs within this ten-year period.

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

NUREG-1801 Consistency

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

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Buried Piping and Tanks Inspection Program is a new program. Plant and industry operating experience will be considered when implementing this program. Industry operating experience that forms the basis for the program is described in the operating experience element of the NUREG-1801 program description. IPEC plant-specific operating experience is not inconsistent with the operating experience in the NUREG-1801 program description.

The IPEC program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, operating experience assures that implementation of the Buried Piping and Tanks Inspection program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Conclusion

The Buried Piping and Tanks Inspection Program will be effective for managing aging effects since it will incorporate proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls. The Buried Piping and Tanks Inspection Program assures the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.7 CONTAINMENT LEAK RATE

Program Description

The Containment Leak Rate Program is an existing program. As described in 10 CFR Part 50, Appendix J, containment leak rate tests are required to assure that (a) leakage through reactor containment and systems and components penetrating containment shall not exceed allowable values specified in technical specifications or associated bases and (b) periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of containment, and systems and components penetrating containment. The IPEC program utilizes 10 CFR 50 Appendix J, Option B, and the guidance in NRC Regulatory Guide 1.163 and NEI 94-01.

NUREG-1801 Consistency

The Containment Leak Rate Program is consistent with the program described in NUREG-1801, Section XI.S4, 10 CFR Part 50, Appendix J.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

Containment leak rate testing at IP2 in 2006 (2R17) was completed successfully. A QA surveillance of the containment leak rate test identified only administrative deficiencies in the procedures used to calculate total leakage. Results of IP3 containment leak rate testing during 2005 (3R13) were satisfactory. Confirmation of containment integrity, along with identification and resolution of program discrepancies, provides assurance that the program is effective for managing loss of material of components.

An industry benchmarking was performed for this program in 2004. Areas for improvement were identified and corrective actions were implemented. A self-assessment of the program was performed in 2003. The focus of the self-assessment was to identify differences between the IP2 and IP3 program procedures. Actions were generated that led to several improvements.

As stated in NUREG-1801, Section XI.S4, 10 CFR 50, Appendix J, "To date, the 10 CFR Part 50, Appendix J, LRT program has been effective in preventing unacceptable leakage through the containment pressure boundary. Implementation of Option B for testing frequency must be consistent with plant-specific operating experience." The program is consistent with the NUREG-1801 Option B program. Based on review of operating history, corrective actions, and self-assessments, the 10CFR Part 50, Appendix J Program is continually monitored and enhanced to incorporate the results of OE; as such it provides an effective means of ensuring the structural integrity and leak tightness of the IP2 and IP3 containments.

Conclusion

The Containment Leak Rate Program has been effective at managing aging effects. The Containment Leak Rate Program provides assurance that the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.8 CONTAINMENT INSERVICE INSPECTION

Program Description

The Containment Inservice Inspection (CII) Program is an existing program encompassing ASME Section XI Subsection IWE and IWL requirements as modified by 10 CFR 50.55a. The IP2 program uses the ASME Boiler and Pressure Vessel Code, Section XI, 1992 Edition, 1992 Addenda. The IP3 program uses the ASME Boiler and Pressure Vessel Code, Section XI, 1998 Edition, no Addenda. Every 10 years, each unit's program is updated to the latest ASME Section XI code edition and addenda approved by the Nuclear Regulatory Commission in 10 CFR 50.55a.

Visual inspections for IWE monitor loss of material of the steel containment liners and their integral attachments; containment hatches and airlocks; moisture barriers; and pressure-retaining bolting by inspecting surfaces for evidence of flaking, blistering, peeling, discoloration, and other signs of distress.

Visual inspections for IWL monitor structural concrete surfaces for evidence of leaching, erosion, voids, scaling, spalls, corrosion, cracking, exposed reinforcing steel, and detached embedment. IP2 and IP3 containments are reinforced concrete structures that do not utilize a post-tensioning system. Therefore, IWL requirements pertaining to post-tensioning do not apply.

Evaluation

1. Scope of Program

The Containment Inservice Inspection Program, under ASME Section XI Subsection IWE, manages aging effects for the containment liners and integral attachments including connecting penetrations and parts forming the leak tight boundary.

The Containment Inservice Inspection Program, under ASME Section XI Subsection IWL provides confirmation that the effects of aging on the reinforced concrete containment walls, domes, and basemats will not prevent the performance of intended functions consistent with the current licensing basis through the period of extended operation.

2. Preventive Actions

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

3. Parameters Monitored or Inspected

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

Visual inspections for IWL monitor concrete surfaces for evidence of leaching, erosion, voids, scaling, spalls, corrosion, cracking, exposed reinforcing steel, and detached embedment.

4. Detection of Aging Effects

The primary inspection method for the steel containment liner and its integral attachments is general visual examination. Components in examination category E-A receive general visual examination or VT-3. Painted or coated areas are examined for evidence of flaking, blistering, peeling, and discoloration. Non-coated areas are examined for evidence of cracking, discoloration, wear, pitting, corrosion, gouges, and surface irregularities. Components in examination category E-C receive an augmented visual or volumetric examination in accordance with IWE Table 2500-1.

The primary inspection method for the concrete containment shell is a general visual examination in accordance with IWL-2500. Detailed visual examinations are performed to provide sufficient data to conduct an acceptance review when conditions exceeding the screening criteria are noted.

5. Monitoring and Trending

Results are compared, as appropriate, to baseline data and other previous test results.

6. Acceptance Criteria

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

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

7. Corrective Actions

ASME Section XI, Subsection IWE states that components whose examination results indicate flaws or areas of degradation that do not meet the acceptance standards are acceptable if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no effect on the structural integrity of the containment. Except as permitted by 10 CFR 50.55a(b)(ix)(D), components that do not meet the acceptance standards are subject to additional examination requirements, and the components are repaired or replaced to the extent necessary to meet the acceptance standards. IPEC corrective actions are in accordance with 10 CFR 50 Appendix B.

ASME Section XI, Subsection IWL components that do not meet the acceptance standards are evaluated by the responsible engineer. An engineering report is prepared which identifies the cause of the condition, documents acceptability without repair, documents if repair or replacement is required, and provides specifics of additional examinations. IPEC corrective actions are in accordance with 10 CFR 50 Appendix B.

8. Confirmation Process

This attribute is discussed in Section B.0.3.

9. Administrative Controls

This attribute is discussed in Section B.0.3.

10. Operating Experience

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

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

An IWL inspection at IP2 in 2005 revealed 91 recordable indications which were reviewed by engineering. None of these indications, which were compared to the results of the 2000 inspection, represented a structural concern. An IWL inspection at IP3 in 2005 found minor spalling and other indications which had been noted in the 2001 inspection and which showed no signs of further degradation. Lack of degradation that could lead to possible failure, demonstrated through a regular program of inspections, provides assurance that the program is effective for managing aging effects for passive components.

A self-assessment of the Containment ISI program was completed in October 2004. All findings and recommendations from earlier EPRI assessments of the program were found to be evaluated, and corrected. Identification of program weaknesses, and subsequent corrective actions, assures that the program will remain effective for managing aging effects of components.

Conclusion

The Containment Inservice Inspection Program has been effective at managing aging effects. The Containment Inservice Inspection Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.9 DIESEL FUEL MONITORING

Program Description

The Diesel Fuel Monitoring Program is an existing program that entails sampling to ensure that adequate diesel fuel quality is maintained to prevent loss of material and fouling in fuel systems. Exposure to fuel oil contaminants such as water and microbiological organisms is minimized by periodically draining and cleaning tanks and by verifying the quality of new oil before its introduction into the storage tanks. Sampling and analysis activities are in accordance with the IP2 and IP3 Technical Specifications for fuel oil purity and the guidelines of ASTM Standards D4057-95 and D975-95 (or later revisions of these standards).

Thickness measurements of storage tank bottom surfaces verify that significant degradation is not occurring.

The One-Time Inspection Program describes inspections planned to verify the effectiveness of the Diesel Fuel Monitoring Program

NUREG-1801 Consistency

The Diesel Fuel Monitoring Program is consistent with the program described in NUREG-1801, Section XI.M30, Fuel Oil Chemistry Program, with exceptions and enhancements.

Exceptions to NUREG-1801

The Diesel Fuel Monitoring Program is consistent with the program described in NUREG-1801, Section XI.M30, Fuel Oil Chemistry Program, with the following exceptions.

Attributes Affected	Exceptions
1. Scope of Program	NUREG-1801 recommends use of ASTM Standards D2276 and D6217. Particulate testing is performed using the guidelines of ASTM Standard D2276.[1] NUREG-1801 recommends use of ASTM Standards D1796 and D2709. Only ASTM Standard D1796 is used for testing water and sediment.[2]
2. Preventive Actions	NUREG-1801 specifies fuel oil is maintained by addition of biocides. IPEC does not add biocide to diesel fuel oil storage tanks.[3]

Attributes Affected	Exceptions
3. Parameters Monitored or Inspected	NUREG-1801 recommends the use of ASTM Standard D2709. Only ASTM Standard D1796 is used for testing water and sediment. [2] NUREG-1801 recommends use of modified ASTM Standard D2276 Method A. Determination of particulates is according to ASTM Standard D2276.[4]
6. Acceptance Criteria	NUREG-1801 recommends the use of ASTM Standards D1796 and D2709. Only ASTM Standard D1796 is used for testing water and sediment. [2] NUREG-1801 recommends the use of modified ASTM Standard D2276 Method A. Determination of particulates is according to ASTM Standard D2276. [4]

Exception Notes

1. ASTM Standard D6217 (particulate by filtration) is not used for determination of particulate. Particulate testing is performed using standard D2276. The guidelines of D2276 are appropriate for determination of particulates and the plant technical specifications specify this standard.
2. The guidelines of ASTM Standard D1796 are used rather than those of ASTM Standard D2709 (water and sediment by centrifuge for lower viscosities) for determination of water and sediment. The two standards are applicable to oils of different viscosities. Standard D1796 is applicable to the fuel oil used at IPEC.
3. IPEC does not add biocides to diesel fuel oil storage tanks. Since water contamination in the diesel fuel storage tanks is minimized, the potential for MIC is limited. The IPEC process for review of site and industry operating experience ensures that if MIC is discovered during future analyses, appropriate corrective actions will be taken, including modification of program attributes, if appropriate.
4. Determination of particulates is according to ASTM Standard D2276 which conducts particulate analysis using a 0.8 micron filter, rather than the 3.0 micron filter specified in NUREG-1801. Use of a filter with a smaller pore size results in a larger sample of particulates since smaller particles are retained. Thus, use of a 0.8 micron filter is more conservative than use of the 3.0 micron filter specified in NUREG-1801.

Enhancements

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

Attributes Affected	Enhancements
2. Preventive Actions 4. Detection of Aging Effects	IP2: Revise applicable procedures to include cleaning and inspection of the GT1 gas turbine fuel oil storage tanks, EDG fuel oil day tanks, and SBO/Appendix R diesel generator fuel oil day tank once every ten years. IP3: Revise applicable procedures to include cleaning and inspection of the EDG fuel oil day tanks, Appendix R fuel oil storage tank, and Appendix R fuel oil day tank once every ten years.
2. Preventive Actions 4. Detection of Aging Effects 5. Monitoring and Trending	IP2: Revise applicable procedures to include quarterly sampling and analysis of the SBO/Appendix R diesel generator fuel oil day tank and security diesel fuel oil day tank. Particulates (filterable solids), water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be $\leq$ 10mg/l. Water and sediment acceptance criterion will be $\leq$ 0.05% IP3: Revise applicable procedures to include quarterly sampling and analysis of the Appendix R fuel oil storage tank. Particulates (filterable solids), water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be $\leq$ 10mg/l. Water and sediment acceptance criterion will be $\leq$ 0.05%

Attributes Affected	Enhancements
4. Detection of Aging Effects	IP2: Revise applicable procedures to include thickness measurement of the bottom surface of the EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/ Appendix R diesel generator fuel day tank, GT1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank once every ten years. IP3: Revise applicable procedures to include thickness measurement of the bottom surface of the EDG fuel oil day tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank once every ten years.
5. Monitoring and Trending	IP2: Revise appropriate procedures to change the GT1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank analysis for water and particulates to a quarterly frequency. IP3: Revise appropriate procedures to change the Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank analysis for water and particulates to a quarterly frequency.
6. Acceptance Criteria	Revise applicable procedures to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program.

Operating Experience

Results of a microorganism study performed by a vendor on a sample taken from an EDG underground diesel fuel tank reported heavy bacteria growth. The source of the bacteria was water intrusion through an overfill line spool piece incorrectly reassembled following maintenance. The water was removed from the tank and subsequent testing verified the absence of bacteria. Identification of out-of-specification fuel conditions demonstrates the ability of the program to detect potentially detrimental conditions in the diesel fuel. Subsequent corrective actions enhance the ability of the program to remain effective for managing loss of material of components.

A QA surveillance in 2004 determined the overall program was effective. One deficiency noted was a missed surveillance. Corrective actions were identified and implemented. Identification of program deficiencies, and subsequent corrective actions, provide added assurance that the program will remain effective for managing loss of material of components.

Other than the above instances, fuel oil sampling results from 2001 through 2005 reveal that fuel oil quality is being maintained in compliance with acceptance criteria. Continuing acceptable diesel fuel quality provides assurance that the program is effective in managing loss of material of fuel system components.

Visual inspection of an IP3 EDG fuel oil storage tank was performed in 2001. Visual and UT inspections of the two other EDG fuel oil storage tanks were also completed in 2001. The IP2 fuel oil storage tanks were visually inspected in 2003. No significant degradation was identified.

Conclusion

The Diesel Fuel Monitoring Program has been effective at managing aging effects. The Diesel Fuel Monitoring Program assures the effects of aging are managed such that applicable components will continue to perform their intended function consistent with the current licensing basis through the period of extended operation.

B.1.10 ENVIRONMENTAL QUALIFICATION OF ELECTRIC COMPONENTS

Program Description

The Environmental Qualification (EQ) of Electric Components Program is an existing program. The Nuclear Regulatory Commission (NRC) has established nuclear station environmental qualification (EQ) requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments (that is, those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high energy line breaks (HELBs) or high radiation) are qualified to perform their safety function in those harsh environments. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

The IPEC EQ program manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components are refurbished, replaced, or their qualification is extended prior to reaching the aging limits established in the evaluation. Some aging evaluations for EQ components are time-limited aging analyses (TLAAs) for license renewal.

EQ Component Reanalysis Attributes

The reanalysis of an aging evaluation is normally performed to extend the qualification by reducing excess conservatism incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of a component is performed on a routine basis pursuant to 10 CFR 50.49(e) as part of an EQ program. While a component life limiting condition may be due to thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, an unrealistically low activation energy, or in the application of a component (de-energized versus energized). The reanalysis of an aging evaluation is documented according to the station's quality assurance program requirements, which requires the verification of assumptions and conclusions. As already noted, important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). These attributes are discussed below.

Analytical Methods: The analytical models used in the reanalysis of an aging evaluation are the same as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (that is, normal radiation dose for the projected installed life plus accident radiation dose). For license renewal, one acceptable method of establishing the 60-year normal radiation dose is to multiply the 40-year normal radiation dose by 1.5 (that is, 60 years/40 years). The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging, a similar approach may be used. Other models may be justified on a case-by-case basis.

Data Collection and Reduction Methods: Reducing excess conservatism in the component service conditions (for example, temperature, radiation, cycles) used in the prior aging evaluation is the chief method used for a reanalysis. Temperature data used in an aging evaluation is to be conservative and based on plant design temperatures or on actual plant temperature data. When used, plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors (while the motor is not running). A representative number of temperature measurements are conservatively evaluated to establish the temperatures used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as (a) directly applying the plant temperature data in the evaluation, or (b) using the plant temperature data to demonstrate conservatism when using plant design temperatures for an evaluation. Any changes to material activation energy values as part of a reanalysis are to be justified on a plant-specific basis. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging.

Underlying Assumptions: EQ component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Actions: The reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component is to be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner (that is, sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful).

NUREG-1801 Consistency

The Environmental Qualification (EQ) of Electric Components Program is consistent with the program described in NUREG-1801, Section X.E1, Environmental Qualification (EQ) of Electrical Components.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

In August 2001, incorrect inputs were identified in EQ analyses. Corrective actions included update of calculations, evaluation of other program documents, and evaluation of environmental conditions. In July 2002, a QA audit of the EQ Program identified differences between the analytical tools used for HELB analyses at IP2 and those used at IP3. Corrective actions included development of revised pressure/temperature profiles and thermal lag evaluations for specific equipment, and revisions to the EQ Program Plan and supporting calculations. A focused self-assessment in 2002 found that the program procurement and work control processes were meeting 10CFR50.49 requirements. In February 2003, the EQ Program was reviewed to determine the impact of the IP2 power uprate. EQ files requiring update were identified and revised. An EQ Master List (EQML) validation project in 2003-2004 led to reviews of wiring diagrams and updates of the EQML.

Condition reports, audits, and self-assessments, along with the associated corrective actions resulting in overall process improvements, provide assurance that the program will remain effective in maintaining equipment within its qualification basis and qualified life.

Conclusion

The Environmental Qualification (EQ) of Electric Components Program has been effective at maintaining equipment within its qualification basis. The Environmental Qualification (EQ) of Electric Components Program assures qualification of applicable electrical components such that the effects of aging will not prevent those components from performing their intended function consistent with the current licensing basis through the period of extended operation.

B.1.11 EXTERNAL SURFACES MONITORING

Program Description

The External Surfaces Monitoring Program is an existing program that inspects external surfaces of components subject to aging management review. The program is also credited with managing loss of material from internal surfaces, for situations in which internal and external material and environment combinations are the same such that external surface condition is representative of internal surface condition.

Surfaces that are inaccessible during plant operations are inspected during refueling outages. Surfaces that are insulated are inspected when the external surface is exposed (i.e., during maintenance). Surfaces are inspected at frequencies to assure the effects of aging are managed such that applicable components will perform their intended function during the period of extended operation.

NUREG-1801 Consistency

The External Surfaces Monitoring Program is consistent with the program described in NUREG-1801, Section XI.M36, External Surfaces Monitoring with an enhancement.

Exceptions to NUREG-1801

None

Enhancements

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

Attributes Affected	Enhancement
1. Scope of Program	External Surfaces Monitoring Program guidance documents will be revised to require periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(2).

Operating Experience

System walkdowns between 2001 and 2005 identified precursors of aging effects, including corrosion and leakage. Corrective actions were accomplished in accordance with the site Corrective Action Program. Identification of degradation and corrective action prior to loss of intended function provide evidence that the program is effective for managing aging effects for passive components.

A review of best practices for system walkdowns at all Entergy sites was performed as part of the development of a fleet-wide program guidance procedure. Comparison of program techniques and development of fleet-standard practices provide assurance that the program is effective for managing aging effects for passive components.

Conclusion

The External Surfaces Monitoring Program has been effective at managing aging effects. The External Surfaces Monitoring Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.12 FATIGUE MONITORING

Program Description

The Fatigue Monitoring Program is an existing program that tracks the number of critical thermal and pressure transients for selected reactor coolant system components. 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.

The transient cycles tracked by this program are referenced in Section 4.3.

NUREG-1801 Consistency

The Fatigue Monitoring Program is consistent with the program described in NUREG-1801, Section X.M1, Metal Fatigue of Reactor Coolant Pressure Boundary, with an exception and enhancement.

Exceptions to NUREG-1801

The Fatigue Monitoring Program is consistent with the program described in NUREG-1801, Section X.M1, Metal Fatigue of Reactor Coolant Pressure Boundary, with the following exception.

Attributes Affected	Exceptions
4. Detection of Aging Effects	NUREG-1801 specifies periodic updates of fatigue usage calculations. The IPEC program updates fatigue usage calculations when the number of actual cycles approach the analyzed number of cycles [1]

Exception Notes

1. Updates of fatigue usage calculations are not necessary unless the number of accumulated fatigue cycles approaches the number of analyzed design cycles. The IPEC program provides for periodic assessment of the number of accumulated cycles. If any transient approaches its number of analyzed cycles, corrective action is taken which may include update of the fatigue usage calculation.

Enhancements

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

Attributes Affected	Enhancement
3. Parameters Monitored or Inspected	IP2: Perform an evaluation to confirm that monitoring steady state cycles is not required or revise appropriate procedures to monitor steady state cycles. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. IP3: Revise appropriate procedures to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.

Operating Experience

The program includes re-evaluation of usage factors as appropriate. For example, certain auxiliary transients related to charging and letdown that were approaching typical design cycle limits for the IP2 charging nozzles, during the current period of operation, were reevaluated. The impact of thermal transient cycles on the IP2 nozzles was assessed based on comparison of plant specific moment loads against previously assumed moment loads and reconciliation of the cycle counts to design cycles used in previous analysis. The reevaluation concluded that the fatigue impact of transient cycles accumulated on the IP2 charging nozzles is within that expected based on pro-rated typical operation of the charging system, and projected allowable cycles during the current period of operation.

Operating experience shows that this program has been effective in managing aging effects. Therefore, continued implementation of the program assures the effects of aging will be managed so that components crediting this program can perform their intended function consistent with the current licensing basis during the period of extended operation.

Conclusion

The Fatigue Monitoring Program has been demonstrated to maintain the validity of the fatigue design basis for reactor coolant system components designed to withstand the effects of cyclic loads due to reactor system transients.

The Fatigue Monitoring Program assures the fatigue design basis is maintained such that applicable components will continue to perform their intended function consistent with the current licensing basis through the period of extended operation.

B.1.13 FIRE PROTECTION

Program Description

The Fire Protection Program is an existing program that includes a fire barrier inspection, an RCP oil collection system inspection, and a diesel-driven fire pump inspection. The fire barrier inspection requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, and periodic visual inspection and functional tests of fire rated doors to ensure that their operability is maintained. The diesel-driven fire pump inspection requires that the pump and its driver be periodically tested and inspected to ensure that diesel engine sub-systems including the fuel supply line can perform their intended functions.

IP2

The program includes periodic inspection and testing of the Halon fire protection system.

IP3

The program includes periodic inspection and testing of the CO_2 fire protection system.

NUREG-1801 Consistency

The Fire Protection Program is consistent with the program described in NUREG-1801, Section XI.M26, Fire Protection with an exception and enhancements.

Exceptions to NUREG-1801

The Fire Protection Program is consistent with the program described in NUREG-1801, Section XI.M26, Fire Protection with the following exception.

Attributes Affected	Exceptions
4. Detection of Aging Effects	The NUREG-1801 program recommends that functional testing and inspection of the Halon (IP2) and CO_2 (IP3) fire suppression systems occur at least once every six months. However, while IPEC performs inspections at least once every six months, functional testing is performed every 18 months for Halon and 24 months for CO_2. [1]

Exception Notes

1. The NRC Staff, as documented in the SER for Oyster Creek, has accepted the position that, in the absence of aging-related events adversely affecting system operation and provided that visual inspections of component external surfaces are performed every six months, the periodicity specified in the current licensing basis for functional testing of the Halon and CO_2 systems is sufficient to ensure system availability and operability. This frequency is sufficient to ensure system availability and operability based on station operating history and to ensure that aging effects will be properly managed through the period of extended operation.

Enhancements

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

Attributes Affected	Enhancement
1. Scope 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	IP3: Revise appropriate procedures to inspect external surfaces of the RCP oil collection system for loss of material each refueling outage.
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Revise appropriate procedures to explicitly state that the diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running, such as fuel oil, lube oil, coolant, or exhaust gas leakage.
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Revise appropriate procedures to specify that diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion or cracking at least once each operating cycle.
4. Detection of Aging Effects 6. Acceptance Criteria	IP3: Revise appropriate procedures to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.

Operating Experience

Inspections of fire stops, fire barrier penetration seals, fire barrier walls, ceilings, and floors from 2001 through 2005, revealed signs of degradation such as cracks, gaps, voids, holes or missing material. Discrepancies in fire barrier wrappings were detected during periodic surveillances in 2001 and 2004. Immediate actions were completed to repair these fire barriers. Identification of deficiencies and timely corrective actions provide evidence that the program will remain effective for managing loss of material of components.

A program self-assessment in 2003 identified deficiencies in the fire barrier inspection list at IP2. Corrective actions included review of the Type I fire barrier drawing against the inspection list in the procedure, followed by changes to the procedure and the drawing. Identification of program weaknesses, and subsequent corrective actions, provide assurance that the program will remain effective for managing loss of material of components.

QA audits in 2003, 2005, and 2006 revealed that the material condition of system equipment was good. The audits revealed no issues or findings that could impact effectiveness of the program to manage aging effects for fire protection components.

A November 2005 inspection of the RCP oil collection system within the IP2 containment building found no indications of loss of material on system components.

The IP2 and IP3 diesel-driven fire pumps were observed while they were running in November 2006. No leaks or degradation of diesel engine sub-systems, including the fuel supply line, were noted. Continuing monitoring provides evidence that the program is effective for managing aging of diesel-driven fire pump subsystem components.

In August 2004, NRC completed a triennial fire protection team inspection at IP2 to assess whether the plant has implemented an adequate fire protection program and that post-fire safe shutdown capabilities have been established and are being properly maintained. The inspection team also evaluated the material condition of fire area boundaries, fire doors, and fire dampers, and reviewed the surveillance and functional test procedures for the diesel fire pump and other components. Additionally, the team reviewed the surveillance procedures for structural fire barriers, penetration seals, and structural steel. No findings of significance were identified. Confirmation of program compliance with established standards and regulations provides assurance that the program will remain effective for managing loss of material of components.

In January 2005, NRC completed a triennial fire protection team inspection at IP3 to assess whether the plant has implemented an adequate fire protection program and that post-fire safe shutdown capabilities have been established and are being properly maintained. The inspection team also evaluated the material condition of fire area boundaries, fire doors, and fire dampers, and reviewed the surveillance and functional test procedures for the diesel fire pump and other components. The inspection team also reviewed the adequacy of selected total flooding CO2 systems. Completed surveillance procedures were also reviewed to ensure appropriate periodic testing of the system was being accomplished. Additionally, the team reviewed the surveillance procedures for structural fire barriers and penetration seals. No findings of significance were identified. Confirmation of program compliance with established standards and regulations provides assurance that the program will remain effective for managing aging effects.

Conclusion

The Fire Protection Program has been effective at managing aging effects. The Fire Protection Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.14 FIRE WATER SYSTEM

Program Description

The Fire Water System Program is an existing program that manages water-based fire protection systems consisting of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, piping, and components that are tested in accordance with applicable National Fire Protection Association (NFPA) codes and standards. Such testing assures functionality of systems. To determine if significant corrosion has occurred in water-based fire protection systems, periodic flushing, system performance testing and inspections are conducted. Also, many of these systems are normally maintained at required operating pressure and monitored such that leakage resulting in loss of system pressure is immediately detected and corrective actions initiated.

In addition, wall thickness evaluations of fire protection piping are periodically performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion.

A sample of sprinkler heads required for 10 CFR 50.48 will be inspected using the guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1. NFPA 25 states, "Where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." This sampling will be repeated every 10 years after initial field service testing.

NUREG-1801 Consistency

The Fire Water System Program is consistent with the program described in NUREG-1801, Section XI.M27, Fire Water System, with an exception and enhancements.

Exceptions to NUREG-1801

The Fire Water System Program is consistent with the program described in NUREG-1801, Section XI.M27, Fire Water System, with the following exceptions.

Attributes Affected	Exception
4. Detection of Aging Effects	NUREG-1801 specifies annual fire hose hydrostatic tests and gasket inspections. Fire hoses and hose station gaskets are not subject to aging management review and not included in the program.[1]

Exception Notes

1. Fire hoses are periodically inspected, hydrotested, and replaced as required in accordance with plant procedures. Gaskets in couplings are replaced during hose station inspections.

Enhancements

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

Attributes Affected	Enhancements
3. Parameters Monitored or Inspected 6. Acceptance Criteria	Revise applicable procedures to include inspection of hose reels for corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation.
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	IP3: Revise applicable procedures to inspect the internal surface of the foam-based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.
4. Detection of Aging Effects	A sample of sprinkler heads required for 10 CFR 50.48 will be inspected using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.
4. Detection of Aging Effects	Wall thickness evaluations of fire protection piping will be performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function.

Operating Experience

In August 2004, NRC completed a triennial fire protection team inspection at IP2 to assess whether the plant has implemented an adequate fire protection program and whether post-fire safe shutdown capabilities have been established and are being properly maintained. The inspection team reviewed the adequacy of selected pre-action and wet pipe sprinklers, including the adequacy of surveillance procedures. No findings of significance were identified Confirmation of program compliance with established standards and regulations provides assurance that the program will remain effective for managing loss of material of components.

In January 2005, NRC completed a triennial fire protection team inspection at IP3 to assess whether the plant has implemented an adequate fire protection program and whether post-fire safe shutdown capabilities have been established and are being properly maintained. The inspection team reviewed the adequacy of selected wet pipe sprinkler systems. Completed surveillance procedures were also reviewed to ensure appropriate periodic testing of the system was being accomplished. Confirmation of program compliance with established standards and regulations provides assurance that the program will remain effective for managing loss of material of components.

Visual inspections of fire hose station equipment in September 2005 at IP3 and in November 2006 at IP2 revealed no loss of material on hose station steel parts. One broken sprinkler nozzle was replaced as a result of the IP2 inspection. Identification of degradation and corrective action prior to loss of intended function provide evidence that the program is effective for managing aging effects for steel fire water system components.

Flow tests of fire main segments and hydrant inspections during 2006 found no evidence of obstruction or loss of material. Spray and sprinkler system functional tests and visual inspections of piping and nozzles in 2006 found no evidence of blockage or loss of material. Confirmation of absence of degradation provides evidence that the program is effective for managing loss of material for fire water system components.

Conclusion

The Fire Water System Program has been effective at managing aging effects. The Fire Water System Program assures the effects of aging are managed such that applicable components will continue to perform their intended function consistent with the current licensing basis through the period of extended operation.

B.1.15 FLOW-ACCELERATED CORROSION

Program Description

The Flow-Accelerated Corrosion (FAC) Program is an existing program that applies to safety-related and nonsafety-related carbon and low alloy steel components in systems containing high-energy fluids carrying two-phase or single-phase high-energy fluid $\geq$ 2% of plant operating time.

The program, based on EPRI guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R2 for an effective flow-accelerated corrosion program, predicts, detects, and monitors FAC in plant piping and other pressure-retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions, or repair or replace components as necessary.

NUREG-1801 Consistency

The FAC Program is consistent with the program described in NUREG-1801, Section XI.M17, Flow-Accelerated Corrosion.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

Operating experience for IP2 and IP3 was accounted for in the most recent updates of the respective CHECWORKS FAC models. This includes inspection data from the outage inspections as well as the changes to FAC wear rates due to the recent power uprates. These updates further calibrate the model, improving the accuracy of the wear predictions.

The FAC program for IP2 was audited in 2004. The audit team determined that this program was effective and in compliance with NRC regulations, ASME code, EPRI standards, and INPO guidelines. Consistency with industry standards and guidelines provide assurance that the program will remain effective for managing aging effects for passive components.

A self-assessment of the FAC Program was performed in February 2006 to evaluate the overall health and effectiveness of the program. The assessment team concluded that IPEC has a well organized and effective FAC Program. The program was found to be consistent with the primary industry standards. No weaknesses or deficiencies were identified that would indicate negatively impact long-term monitoring of FAC.

During 3R13 in March 2005, wall thinning was detected on vent chamber drain and high pressure turbine drain components which were replaced during that outage. These systems are susceptible to FAC and are closely monitored. Susceptible sections of these systems are being replaced with FAC resistant chrome-moly material. All remaining inspected components were found acceptable for continued service. During 2R17 in May 2006, wall thinning was detected in a steam trap pipe which was then replaced during that outage. Identification of degradation and corrective action prior to loss of intended function provide assurance that the program is effective for managing aging effects due to flow accelerated corrosion.

A review of best practices for the FAC Program at all Entergy sites was performed as part of the development of a fleet-wide program procedure. Guidance from the EPRI CHECWORKS User's Group (CHUG) has been applied to this procedure. Conformance to industry standards and use of fleet-wide "best practices" in the development of procedures provide assurance that the program will remain effective for managing aging effects for passive components.

Conclusion

The FAC Program has been effective at managing aging effects. The FAC Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.16 FLUX THIMBLE TUBE INSPECTION

Program Description

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

NUREG-1801 Consistency

The Flux Thimble Tube Inspection Program is consistent with the program described in NUREG-1801, Section X.M37, Flux Thimble Tube Inspection, with enhancements.

Exceptions to NUREG-1801

None

Enhancements

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

Attributes Affected	Enhancements
5. Monitoring and Trending	Revise appropriate procedures to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope.
6. Acceptance Criteria	Revise appropriate procedures to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results.

Attributes Affected	Enhancements
7. Corrective Actions	Revise appropriate procedures to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate in procedures that flux thimble tubes that cannot be inspected over the tube length and can not be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.

Operating Experience

Flux thimble tube inspections were performed at IP2 in March 1989. An inspection plan was developed using the inspection results and methodology provided in WCAP-12866.

Flux thimble tube inspections were performed at IP3 during May 1997 and May 2001. Comparison of 1997 results to 2001 results for each tube showing indications of wall loss revealed, in general, that tubes had either no significant increase in wall loss, or an increase of 20% or less over four years. All 2001 recorded wall losses were below the maximum allowed per vendor guidelines. Identification of degradation prior to loss of function is an indication that the program is effective for managing aging effects in these components.

Conclusion

The Flux Thimble Tube Inspection Program has been effective at managing aging effects. The Flux Thimble Tube Inspection Program assures the effects of aging are managed such that applicable components will continue to perform their intended function consistent with the current licensing basis through the period of extended operation.

B.1.17 HEAT EXCHANGER MONITORING

Program Description

The Heat Exchanger Monitoring Program is an existing plant-specific program that inspects heat exchangers for loss of material through visual or other non-destructive examination.

Heat exchanger tubes are inspected at frequencies based on plant-specific and application-specific knowledge, as well as past history, heat exchanger operating conditions, and heat exchanger availability. Inspection frequencies may be changed based on engineering evaluation of inspection results.

Evaluation

1. Scope of Program

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

Enhancement: Enhance applicable procedures to include the following heat exchangers in the scope of the program.

- safety injection pump lube oil heat exchangers
- RHR heat exchangers
- RHR pump seal coolers
- non-regenerative heat exchangers
- charging pump seal water heat exchangers
- charging pump fluid drive coolers
- instrument air heat exchangers (IP3 only)
- spent fuel pit heat exchangers
- secondary system steam generator sample coolers
- waste gas compressor heat exchangers
- SBO/Appendix R diesel jacket water heat exchanger (IP2 only)

2. Preventive Actions

This is an inspection program and no actions are taken as part of this program to prevent degradation.

3. Parameters Monitored or Inspected

Visual or other non-destructive examinations of shell-and-tube heat exchanger tubes are performed to determine tube wall thickness, thereby managing the aging effect of loss of material.

Enhancement: Revise appropriate procedures to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current testing, is not possible due to heat exchanger design limitations.

4. Detection of Aging Effects

Loss of material is the aging effect managed by this program. Representative tubes within the sample population of heat exchangers are inspected at a frequency determined by plant-specific and industry operating experience to ensure that effects of aging are identified prior to loss of intended function.

An appropriate sample population of heat exchangers is determined based on operating experience prior to inspections. The sample population of heat exchangers is determined based on the materials of construction of the heat exchanger tubes and the associated environments as well as the type of heat exchanger (for example, shell and tube type). Inspection can reveal loss of material that could result in degradation of the heat exchangers.

Enhancement: Revise appropriate procedures to include consideration of material-environment combination when determining sample population of heat exchangers.

Components whose inspection results continually indicate no new indications from previous inspections are candidates for inspection frequency lengthening. Conversely, the inspection frequencies for components with indications of an increasing trend when compared to previous inspections are evaluated for an increase in inspection frequency.

5. Monitoring and Trending

Results are evaluated against established acceptance criteria and an assessment made regarding the applicable degradation mechanism, degradation rate and allowable degradation level. This information is used to develop future inspection scope, to modify inspection frequency, or replacement of the component if appropriate. Wall thickness is trended and projected to the next inspection. Corrective actions are taken if projections indicate that the acceptance criteria may not be met at the next inspection.

6. Acceptance Criteria

The minimum acceptable tube wall thickness for each heat exchanger inspected is based upon a component specific engineering evaluation. Wall thickness is acceptable if greater than the minimum wall thickness for the component.

Enhancement: Revise appropriate procedures establishing the minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Revise appropriate procedures establishing acceptance criteria for heat exchangers visually inspected to include no unacceptable signs of degradation.

7. Corrective Actions

This program is administered under the site QA program which meets requirements of 10 CFR Part 50, Appendix B. Condition reports are initiated to evaluate extent of condition and for trending purposes.

8. Confirmation Process

This attribute is discussed in Section B.0.3.

9. Administrative Controls

This attribute is discussed in Section B.0.3.

10. Operating Experience

Results of eddy current testing of the tubes for several different IP2 heat exchangers during 2000 through 2006 have been used to determine which tubes should be plugged, thus preventing the loss of the pressure boundary intended function. Identification of degradation and corrective action prior to loss of intended function provide evidence that the program is effective for managing aging effects for passive components.

A review of the IP2 heat exchanger inspection plan was completed in September 2003. This review compared the scope of the IP2 inspections planned for 2R16 (2004) against the typical scope of inspections planned for an IP3 refueling outage. Recommended changes in the IP2 inspection scope were identified and implemented. Use of shared "best practices" in the development of inspection plans provides assurance that the program will remain effective for managing aging effects for passive components.

Results of eddy current testing of the tubes for several different IP3 heat exchangers during 1997 through 2004 have been used to determine which tubes should be plugged, thus preventing the loss of the pressure boundary intended function. Program experience with identification of degradation and performance of corrective action prior to loss of intended function provide evidence that the program is effective for managing aging effects for passive components.

A review of inspection intervals for IP3 components was performed in April 2003. This ongoing plan includes programmatic and technical activities for a wide range of heat exchangers at IP3, and is used to track improvements and corrective actions for the program. Identification of program weaknesses, and subsequent corrective actions, provide assurance that the program will remain effective for managing loss of material of components.

Enhancements

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

Attributes Affected	Enhancements
1. Scope of Program	Revise applicable procedures to include the following heat exchangers in the scope of the program. • safety injection pump lube oil heat exchangers • RHR heat exchangers • RHR pump seal coolers • non-regenerative heat exchangers • charging pump seal water heat exchangers • charging pump fluid drive coolers • instrument air heat exchangers (IP3 only) • spent fuel pit heat exchangers • secondary system steam generator sample coolers • waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water heat exchanger (IP2 only)
3. Parameters Monitored or Inspected	Revise appropriate procedures to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations
4. Detection of Aging Effects	Revise appropriate procedures to include consideration of material-environment combination when determining sample population of heat exchangers.

Attributes Affected	Enhancements
6. Acceptance Criteria	Revise appropriate procedures establishing the minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Revise appropriate procedures establishing acceptance criteria for heat exchangers visually inspected to include no unacceptable signs of degradation.

Conclusion

The Heat Exchanger Monitoring Program assures the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.18 INSERVICE INSPECTION

Program Description

The Inservice Inspection (ISI) Program is an existing program that encompasses ASME Section XI, Subsections IWA, IWB, IWC, IWD and IWF requirements.

Regulation 10 CFR 50.55a, imposes inservice inspection (ISI) requirements of ASME Code, Section XI, for Class 1, 2, and 3 pressure-retaining components, their integral attachments, and supports in light-water cooled power plants. Inspection, repair, and replacement of these components are covered in Subsections IWA, IWB, IWC, IWD, and IWF, respectively. The program includes periodic visual, surface, and volumetric examination and leakage tests of Class 1, 2, and 3 pressure-retaining components, their integral attachments and supports.

Inservice inspection of supports for ASME piping and components is addressed in Section XI, Subsection IWF. ASME Code Section XI, Subsection IWF constitutes an existing mandated program applicable to managing aging of ASME Class 1, 2, 3, and MC supports for license renewal.

The program uses nondestructive examination (NDE) techniques to detect and characterize flaws. Three different types of examinations are volumetric, surface, and visual. Volumetric examinations using methods such as radiographic, ultrasonic or eddy current examinations are used to locate surface and subsurface flaws. Surface examinations, such as magnetic particle or dye penetrant testing, are used to locate surface flaws.

Three levels of visual examinations are specified. VT-1 visual examination is conducted to assess condition of the surface of the part being examined, looking for cracks and symptoms of wear, corrosion, erosion or physical damage. It can be done with either direct visual observation or with remote examination using various optical/video devices. The VT-2 examination is conducted specifically to locate evidence of leakage from pressure retaining components (period pressure tests). While the system is under pressure for a leakage test, visual examinations are conducted to detect direct or indirect indication of leakage. The VT-3 examination is conducted to determine the general mechanical and structural condition of components and supports and to detect discontinuities and imperfections.

The ISI Program is based on ASME Section XI Inspection Program B (IWA-2432), which has ten-year inspection intervals. Every ten years the program is updated to the latest ASME Section XI code edition and addendum in 10 CFR 50.55a.

On July 1, 1994, IP2 entered the third ISI interval and on July 21, 2000, IP3 entered to third ISI interval. The ASME code edition and addenda used for the third interval for both units is the 1989 Edition with no addenda.

The program consists of periodic volumetric, surface, and visual examination of components and their supports for assessment, signs of degradation, flaw evaluation and corrective actions. Augmented inservice inspections are also included as required by 10 CFR 50.55a, the NRC, response to requests for additional information (RAIs), or as deemed necessary by the ISI Program.

Evaluation

1. Scope of Program

The ISI Program provides the requirements for ISI, repair, and replacement. The components within the scope of the program are specified in Subsections IWB-1100, IWC-1100, IWD-1100, and IWF-1100 for Class 1, 2, and 3 components and supports, Quality Groups A, B, and C respectively, and include all pressure-retaining components and their integral attachments. The components described in Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the examination requirements of Subsections IWB-2500, IWC-2500, and IWD-2500.

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

2. Preventive Actions

The ISI Program is a condition monitoring program that does not include preventive actions.

3. Parameters Monitored or Inspected

The program uses nondestructive examination (NDE) techniques to detect and characterize flaws. Volumetric examinations such as radiographic, ultrasonic or eddy current examinations are used to locate surface and subsurface flaws. Surface examinations, such as magnetic particle or dye penetrant testing, are used to locate surface flaws. Visual examinations detect cracks and symptoms of wear, corrosion, physical damage, evidence of leakage, and general mechanical and structural condition.

4. Detection of Aging Effects

The ISI Program manages cracking on subcomponents of the reactor vessel, as applicable, for carbon steel, nickel alloy, carbon steel with stainless steel cladding, and stainless steel components, including bolting, using NDE techniques specified in ASME Section XI, Subsection IWB examination category.

The ISI Program manages loss of material due to wear on reactor vessel internal subcomponents, as applicable, for nickel alloy and stainless steel clevis inserts, radial keys, core alignment pins, and head/vessel alignment pins using NDE techniques specified in ASME Section XI, Subsections IWB examination categories.

The ISI Program manages cracking on reactor coolant system components, as applicable, for carbon steel, carbon steel with stainless steel cladding, stainless steel and cast austenitic stainless steel components, including bolting and support skirts, using NDE techniques specified in ASME Section XI, Subsections IWB examination categories. The Inservice Inspection Program also manages reduction of fracture toughness for valve bodies and pump casing made of cast austenitic stainless steel.

The ISI Program manages cracking on steam generator system components, as applicable, for carbon steel, carbon steel with stainless steel cladding, and stainless steel components, using NDE techniques specified in ASME Section XI, Subsections IWB examination categories.

The ISI Program manages loss of material for ASME Class MC and Class 1, 2, and 3 piping and component supports and their anchorages and base plates by visual examination of components using NDE techniques specified in ASME Section XI, Subsection IWF examination categories.

No aging effects requiring management are identified for lubrite sliding supports. However, the ISI Program will confirm the absence of aging effects through the period of extended operation.

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

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

For both IP2 and IP3, Article IWF of ASME Section XI, 1989 Edition, does not contain any specific exemption criteria for component supports. Components exempt from examination are in accordance with the criteria contained in Code Case N-491-2, Alternate Rules for Examination of Class 1, 2, 3 and MC Component Supports of Light-Water Cooled Power Plants, Section XI, Division 1, IWF-1230.

5. Monitoring and Trending

Results are compared, as appropriate, to baseline data and other previous test results. Indications are evaluated in accordance with ASME Section XI. If the component is qualified as acceptable for continued service, the area containing the indication is reexamined during subsequent inspection periods. Examinations that reveal indications that exceed the acceptance standards are extended to include additional examinations in accordance with ASME Section XI.

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

6. Acceptance Criteria

A preservice, or baseline, inspection of program components was performed prior to startup to assure freedom from defects greater than code-allowable. This baseline data also provides a basis for evaluating subsequent inservice inspection results. Since plant startup, additional inspection criteria for Class 2 and 3 components have been imposed by 10 CFR 50.55a for which baseline and inservice data has also been obtained. Results of inservice inspections are compared, as appropriate, to baseline data, other previous test results, and acceptance criteria of the ASME Section XI, for evaluation of any evidence of degradation.

The ISI Program acceptance standards for flaw indications, repair procedures, system pressure tests and replacements for ASME Class 1, 2, and 3 components and piping are defined in ASME Section XI subsections IWA, IWB, and IWC paragraphs 3000, 4000, 5000 and 7000, respectively. Acceptance standards for examination evaluations, repair procedures, inservice test requirements, and replacements for ASME Class 1 component and piping supports are defined in ASME Section XI paragraphs IWF-3000, IWF-4000, IWF-5000 and IWF-7000, respectively.

7. Corrective Actions

If a flaw is discovered during an ISI examination, an evaluation is conducted in accordance with articles IWA-3000 as appropriate. If flaws exceed acceptance standards, such flaws are removed or repaired, or the component is replaced prior to its return to service. For Class 1, 2, and 3, repair and replacement are in conformance with IWA-4000 and IWA-7000. Acceptance of flaws which exceed acceptance criteria may be accomplished through analytical evaluation without repair, removal or replacement of the flawed component if the evaluation meets the criteria specified in the applicable article of the code. Corrective actions for this program will be administered under the site QA program which meets requirements of 10 CFR Part 50, Appendix B.

8. Confirmation Process

This attribute is discussed in Section B.0.3.

9. Administrative Controls

This attribute is discussed in Section B.0.3.

10. Operating Experience

ISI examinations at IP2 and IP3 were conducted during 2004 and 2005. Results found to be outside of acceptable limits were either repaired, evaluated for acceptance as is, or replacement activities were initiated. Identification of degradation and performance of corrective action prior to loss of intended function are indications that the program is effective for managing aging effects.

A self-assessment of the ISI program was completed in October 2004. Review of current scope for 2R16 (2004) and 3R13 (2005) verified that the proper inspection percentages had been planned for both outages. A follow-up assessment was held for IP2 in March 2006 to ensure that all inspection activities required to close out the third 10-year ISI interval were scheduled for 2R17 (2006). Confirmation of compliance to program requirements provides assurance that the program will remain effective for managing loss of material of components.

QA surveillances in 2005 and 2006 revealed no issues or findings that could impact effectiveness of the program.

Enhancements

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

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

Conclusion

The ISI Program has been effective at managing aging effects. The ISI Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.19 MASONRY WALL

Program Description

The Masonry Wall Program is an existing program that manages aging effects so that the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation.

The program includes visual inspection of all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. Included components are 10 CFR 50.48-required masonry walls, radiation shielding masonry walls, and masonry walls with the potential to affect safety-related components. Structural steel components of masonry walls are managed by the Structures Monitoring Program.

Masonry walls are visually examined at a frequency selected to ensure there is no loss of intended function between inspections.

NUREG-1801 Consistency

The Masonry Wall Program is consistent with the program described in NUREG-1801, Section XI.S5, Masonry Wall Program, with enhancement.

Exceptions to NUREG-1801

None

Enhancements

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

Attributes Affected	Enhancements
1. Scope of Program	Revise applicable procedures to specify that the IP1 intake structure is included in the program.

Operating Experience

Inspections of the IP2 fan house in 2001 identified cracking and spalling in some walls. These conditions did not affect the structural integrity of the walls and were repaired. Slight corrosion of column to wall connections was noted. This corrosion did not affect the structural integrity of the connections and was listed for future monitoring.

Inspections of the IP2 fuel storage building in 2003 identified some hairline cracks and loose blocks which were listed for future monitoring.

Inspections of the IP2 control building in 2003 found indications of water intrusion, evidenced only by efflorescence on the concrete floor. This condition did not affect the structural integrity of the walls.

Inspections of the IP3 primary auxiliary building, fuel storage building, fan house, and turbine building in 2003 through 2005 noted minor cracking in some walls which had not changed from the baseline condition, and some leaking seals which were repaired. A crack in the joint between the fuel storage building and the fan house was noted as acceptable with future monitoring.

Inspections of the city water metering house in 2004 identified some hairline cracks and loose blocks which were found to be acceptable but listed for future monitoring.

Inspections in 2004 discovered minor cracks and spalling in the IP2 turbine building which did not affect structural integrity and were listed for future monitoring.

Inspections of the IP3 control building in 2005 revealed hairline cracks in the battery room walls which were found to be acceptable with no affect on structural integrity. These cracks were not of a nature that requires future monitoring.

Inspections of the IP3 fan house in 2006 found hairline cracks which did not affect the structural integrity of the walls and were listed for future monitoring.

Inspections of the IP3 fuel storage building in 2006 found minor shrinkage cracking along the mortar joints on the outside of the south wall, with no observable change in width since the baseline inspection. These conditions did not affect the structural integrity of the walls.

Identification of degradation and performance of corrective action prior to loss of intended function provide evidence that the program is effective for managing cracking of masonry walls and masonry wall joints.

Conclusion

The Masonry Wall Program has been effective at managing aging effects. The Masonry Wall Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.20 METAL-ENCLOSED BUS INSPECTION

Program Description

The Metal-Enclosed Bus Inspection Program is an existing program that inspects the following non-segregated phase bus.

- IP2/IP3 - 6.9kV bus between station aux transformers and switchgear buses 1/2/3/4/5/6
- IP3 - 6.9kV bus associated with the gas turbine substation
- IP2 - 480V bus associated with substation A
- IP2/IP3 - 480V bus between emergency diesel generators and switchgear buses 2A/3A/5A/6A

Inspections are performed for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. Bus insulation is inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. Internal bus supports are inspected for structural integrity and signs of cracks. Since bolted connections are covered with heat shrink tape or insulating boots per manufacturer's recommendations, a sample of accessible bolted connections is visually inspected for insulation material surface anomalies. Enclosure assemblies are visually inspected for evidence of loss of material.

NUREG-1801 Consistency

The Metal-Enclosed Bus Inspection Program is consistent with the program attributes described in NUREG-1801, Section XI.E4, Metal-Enclosed Bus, with enhancements and exceptions.

Exceptions to NUREG-1801

The Metal-Enclosed Bus (MEB) Inspection Program is consistent with the program described in NUREG-1801, Section XI.E4, Metal-Enclosed Bus Aging Management Program, with the following exceptions.

Attributes Affected	Exception
3. Parameters Monitored or Inspected	NUREG-1801 specifies this program provides for the inspection of the internal portion of the MEBs. The IPEC program specifies visual inspection of the external surfaces of the MEB enclosure assemblies in addition to internal portions.[1]

Attributes Affected	Exception
4. Detection of Aging Effects	NUREG-1801 specifies this program provides for the inspection of the internal portion of the MEBs. IPEC inspects the MEB enclosure assemblies externally in addition to internal surfaces.[1]

Exception Notes

1. Inspection of the external portion of MEB enclosure assemblies under the Metal-Enclosed Bus Inspection Program assures that effects of aging will be identified prior to loss of intended function. Visual inspections have been proven effective in detecting indications of loss of material.

Enhancements

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

Attributes Affected	Enhancements
1. Scope of Program	Revise appropriate procedures to add IP2 480V bus associated with substation A to the scope of bus inspected.
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Revise appropriate procedures to visually inspect the external surface of MEB external enclosure assemblies for loss of material at least once every ten years. The acceptance criterion will be no significant loss of material.
4. Detection of Aging Effects	Revise appropriate procedures to inspect bolted connections visually at least once every five years or at least once every ten years using thermography.

Operating Experience

A comparison of techniques for the cleaning and inspection of metal-enclosed buses at IP2 and IP3 was performed to develop a site-wide program procedure. Input from a review of NRC Information Notice 2000-014 was also used for this procedure. Comparison of program techniques and use of industry findings in the development of site-wide procedures provide assurance that the program will remain effective for managing aging effects for passive components.

Conclusion

The Metal-Enclosed Bus Inspection Program is effective at managing aging effects. The Metal-Enclosed Bus Inspection Program assures the effects of aging are managed such that the applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.21 NICKEL ALLOY INSPECTION

Program Description

The Nickel Alloy Inspection Program is an existing program that manages aging effects of Alloy 600 items and 82/182 welds in the reactor coolant system that are not addressed by the Reactor Vessel Head Penetration Inspection Program, Section B.1.31, or the Steam Generator Integrity Program, Section B.1.35. The aging effect requiring management for nickel alloys exposed to borated water at an elevated temperature is primary water stress corrosion cracking (PWSCC). The Nickel Alloy Inspection Program includes elements of the Inservice Inspection (ISI) Program, Section B.1.18, which specifies the nondestructive examination (NDE) techniques and acceptance criteria applied to evaluation of identified cracks, and the Boric Acid Corrosion Control Program, Section B.1.5. Also, the Water Chemistry Control - Primary and Secondary Program, Section B.1.41, maintains primary water in accordance with the Electric Power Research Institute (EPRI) guidelines to minimize the potential for crack initiation and growth.

IPEC will continue to implement commitments associated with (1) NRC Orders, Bulletins and Generic Letters associated with nickel alloys and (2) staff accepted industry guidelines.

Evaluation

1. **Scope of Program**

   The following items are within the scope of the Nickel Alloy Inspection Program.

Component	Item	Description
Reactor vessel	Inlet and outlet nozzle weld material	Stainless steel clad carbon steel nozzles attached to stainless steel safe-ends using Inconel (82/182) weld material.
	Bottom mounted instrumentation penetrations	The bottom mounted instrumentation (BMI) tubes contain a section of Inconel 182 and are attached to the vessel bottom head with a partial penetration weld.
	Core support lugs (pads)	Support lugs are made of Alloy 600 weld-attached at equal distances around the bottom inside surface of the lower vessel shell.
	Closure head vent safe ends and welds	Closure head vent safe end is SB-166 with Inconel 182 welds

Component	Item	Description
Reactor Coolant System Pressure Boundary	Head vent and reactor flange leakoff piping	The head vent and reactor flange leakoff piping contain nickel alloy.

2. Preventive Actions

No actions are taken as part of this program to prevent aging effects or mitigate aging degradation. However, primary water chemistry is maintained in accordance with EPRI guidelines by the Water Chemistry Control – Primary and Secondary Program, which minimizes the potential for PWSCC.

3. Parameters Monitored or Inspected

The Nickel Alloy Inspection Program detects degradation by using the examination and inspection requirements of ASME Section XI, augmented as appropriate in response to NRC Orders, Bulletins and Generic Letters, or to accepted industry guidelines. The parameters monitored are the presence and extent of cracking.

4. Detection of Aging Effects

The Nickel Alloy Inspection Program detects cracking due to PWSCC prior to loss of component intended function. Some of the nickel alloy locations receive volumetric, surface and visual examination in accordance with ASME Section XI, supplemented as appropriate for current industry PWSCC considerations. Items receiving volumetric, surface and visual examination are listed below.

- Reactor vessel nozzle-to-safe end dissimilar metal welds receive a visual inspection every other outage and examination by volumetric techniques at 10 year intervals per ASME Section XI, Examination Category B-F.
- Bottom mounted instrumentation (BMI) nozzles receive a visual examination from the exterior of the vessel in accordance with ASME Section XI, Examination Category B-P.
- The core support pads and guide lugs receive a visual examination in accordance with ASME Section XI, Examination Category B-N-2.
- The head vent and reactor flange leakoff piping receive a visual examination.

The EPRI MRP in conjunction with the Westinghouse owners groups (WOG) is developing a strategic plan to manage and mitigate PWSCC of nickel based alloy items. The main goal of this program will be to provide short and long term guidance for inspection, evaluation, and management of nickel alloy material and weld metal locations in PWR primary systems. Guidance developed by the MRP and WOG will be used to identify critical locations for inspection and augment existing ISI inspections where appropriate.

5. Monitoring and Trending

Records of the inspection program, examination and test procedures, examination/ test data, and corrective actions taken or recommended are maintained in accordance with the requirements of ASME Section XI, Subsection IWA.

6. Acceptance Criteria

Acceptance criteria for the volumetric inspections of dissimilar metal welds will be in accordance with ASME Section XI, IWB-3514. The acceptance standards for visual examination are specified in MRP-139. Acceptance standards for visual inspection of the core support pads are given in IWB-3520. Acceptance criteria for identified external surface damage, such as from borated water leaks, are given in ASME Section XI, IWA-5250.

Should additional inspections (volumetric, surface or visual) of nickel-based alloy locations (weld and base metal) be identified based on industry operating experience, where acceptance standards are not included in ASME Section XI, acceptance standards will be developed using appropriate analytical techniques.

7. Corrective Actions

Inspection results that do not meet the acceptance criteria are evaluated for continued service and repaired in accordance with the requirements of ASME Section XI.

8. Confirmation Process

This attribute is discussed in Section B.0.3.

9. Administrative Controls

This attribute is discussed in Section B.0.3.

10. Operating Experience

The Nickel Alloy Inspection Program incorporates proven monitoring techniques and acceptance criteria for detection of cracking in nickel alloy components prior to a loss of function. Reactor coolant pressure boundary (RCPB) inspections for IPEC have not identified any indications of cracking of nickel alloy components. The program considers industry operating experience and is responsive to the industry trend in inspections, evaluations, repair, and mitigation activities and is structured to be compatible with corresponding programs in place across the industry. In response to

NRC Bulletin 2003-02, a bare-metal visual examination of the lower head of the reactor vessel was conducted in the fall of 2004 for IP2, and in the spring of 2005 for IP3. The area adjacent to each bottom mounted instrumentation (BMI) penetration was examined, including each Alloy 600 penetration, the nickel alloy weld pad and the circumference around the annulus between the penetration and weld pad. Cracking was not detected.

Conclusion

The Nickel Alloy Inspection Program is effective for managing aging effects. The Nickel Alloy Inspection Program assures the effects of aging are managed such that the applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.22 NON-EQ BOLTED CABLE CONNECTIONS

Program Description

The Non-EQ Bolted Cable Connections Program is a new program. Cable connections are used to connect cable conductors to other cables or electrical devices. Connections associated with cables within the scope of license renewal are considered for this program. The most common types of connections used in nuclear power plants are splices (butt or bolted), crimp-type ring lugs, connectors, and terminal blocks. Most connections involve insulating material and metallic parts. This aging management program for electrical cable connections (metallic parts) monitors for loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. This program does not apply to the high voltage (> 35kV) switchyard connections.

The Metal Enclosed Bus Program manages aging effects from thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation on the metallic parts of MEB connections. Therefore, MEB connections are not included in this program.

Circuits exposed to appreciable ohmic or ambient heating during operation may experience loosening related to repeat cycling of connected loads or cycling of the ambient temperature. Bolted connectors, splices, and terminal blocks may loosen if subjected to significant thermally induced cyclic stress.

The design of these connections will account for the stresses associated with ohmic heating, thermal cycling, and dissimilar metal connections. Therefore, these stressors / mechanisms should not be a significant issue. However, confirmation of the lack of these effects is warranted.

This program provides for one-time inspections on a sample of connections that will be completed prior to the period of extended operation. The factors considered for sample selection will be application (medium and low voltage, defined as < 35 kV), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selections will be documented. If an unacceptable condition or situation is identified in the selected sample, the corrective action program will be used to evaluate the condition and determine appropriate corrective action.

This program will ensure that electrical cable connections will perform their intended function through the period of extended operation and will be implemented prior to the period of extended operation.

Evaluation

1. Scope of Program

Non-EQ connections associated with cables in scope of license renewal are part of this program. This program does not include the high voltage (> 35kV) switchyard connections. In-scope connections are evaluated for applicability of this program. The criteria for including connections in the program are that the connection is a bolted connection that is not covered under the EQ program or an existing preventive maintenance program.

2. Preventive Actions

This one-time inspection program is a condition monitoring program; therefore, no actions are taken as part of this program to prevent or mitigate aging degradation.

3. Parameters Monitored or Inspected

This program will focus on the metallic parts of the cable connections. The one-time inspection verifies that loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation is not an aging effect that requires a periodic aging management program.

4. Detection of Aging Effects

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

5. Monitoring and Trending

Trending actions are not included as part of this program because this is a one-time inspection program.

6. Acceptance Criteria

The acceptance criteria for each inspection / surveillance are defined by the specific type of inspection or test performed for the specific type of cable connections. Acceptance criteria ensure that the intended functions of the cable connections can be maintained consistent with the current licensing basis.

7. Corrective Actions

If the inspection or test acceptance criteria are not met, the requirements of 10 CFR Part 50, Appendix B, will be used to address corrective actions. The corrective action program will be used to perform an evaluation that will consider extent of condition, the indications of aging effects, and possible changes to the one-time inspection program such as frequency and sample size.

8. Confirmation Process

This attribute is discussed in Section B.0.3.

9. Administrative Controls

This attribute is discussed in Section B.0.3.

10. Operating Experience

Operating experience has shown that loosening of connections and corrosion of connections could be a problem without proper installation and maintenance activities. Industry operating experience supports performing this one-time inspection program in lieu of a periodic testing program. This one-time inspection program will verify that the installation and maintenance activities are effective.

The Non-EQ Bolted Cable Connection Program is a new program. Industry and plant-specific operating experience will be considered when implementing this program.

Conclusion

The Non-EQ Bolted Cable Connections Program will be effective for managing aging effects since it will incorporate proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls. The Non-EQ Bolted Cable Connections Program assures the effects of aging will be managed such that applicable cable connections will continue to perform their intended function consistent with the current licensing basis through the period of extended operation.

B.1.23 NON-EQ INACCESSIBLE MEDIUM-VOLTAGE CABLE

Program Description

The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that entails periodic inspections for water collection in cable manholes and periodic testing of cables. In scope medium-voltage cables (cables with operating voltage from 2kV to 35kV) exposed to significant moisture and voltage will be tested at least once every ten years to provide an indication of the condition of the conductor insulation. The program includes inspections for water accumulation in manholes at least once every two years.

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

NUREG-1801 Consistency

The Non-EQ Inaccessible Medium-Voltage Cable Program will be consistent with the program attributes described in NUREG-1801, Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

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

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

Conclusion

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

B.1.24 NON-EQ INSTRUMENTATION CIRCUITS TEST REVIEW

Program Description

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

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

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

NUREG-1801 Consistency

The Non-EQ Instrumentation Circuits Test Review Program will be consistent with NUREG-1801, Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

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

The IPEC program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, this program assures the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Conclusion

The Non-EQ Instrumentation Circuits Test Review Program will incorporate proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls. The Non-EQ Instrumentation Circuits Test Review Program assures the effects of aging will be managed such that applicable components will perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.25 NON-EQ INSULATED CABLES AND CONNECTIONS

Program Description

The Non-EQ Insulated Cables and Connections Program is a new program that assures the intended functions of insulated cables and connections exposed to adverse localized environments caused by heat, radiation and moisture can be maintained consistent with the current licensing basis through the period of extended operation. An adverse localized environment is significantly more severe than the specified service condition for the insulated cable or connection.

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

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

NUREG-1801 Consistency

The Non-EQ Insulated Cables and Connections Program will be consistent with the program described in NUREG-1801, Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

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

The IPEC program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, this program assures the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Conclusion

The Non-EQ Insulated Cables and Connections Program will be effective for managing aging effects since it will incorporate proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls. The Non-EQ Insulated Cables and Connections Program assures the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.26 OIL ANALYSIS

Program Description

The Oil Analysis Program is an existing program that maintains oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil for detrimental contaminants, water, and particulates.

Sampling frequencies are based on vendor recommendations, accessibility during plant operation, equipment importance to plant operation, and previous test results.

The One-Time Inspection Program includes inspections planned to verify the effectiveness of the Oil Analysis Program.

NUREG-1801 Consistency

The Oil Analysis Program is consistent with the program described in NUREG-1801, Section XI.M39, Lubricating Oil Analysis, with the following exception.

Exceptions to NUREG-1801

The Oil Analysis Program is consistent with the program described in NUREG-1801, Section XI.M39, Lubricating Oil Analysis with the following exception.

Attributes Affected	Exception
3. Parameters Monitored or Inspected	NUREG-1801 requires determination of flash point for components that do not have regular oil changes to verify the oil is suitable for continued use. IPEC does not determine flash point for systems that are not potentially exposed to hydrocarbons. For lubricating oil systems potentially exposed to hydrocarbons, fuel dilution testing is performed in lieu of flash point testing.[1]

Exception Note

1. While it is important from an industrial safety perspective to monitor flash point, it has little significance with respect to the effects of aging. Analyses of filter residue or particle count, viscosity, total acid/base (neutralization number), water content, fuel dilution, and metals content provide sufficient information to verify the oil is suitable for continued use. IPEC performs a fuel dilution test in lieu of flash point testing on emergency diesel generators and IP3 Appendix R diesel generator lubricating oils. This test accomplishes the same goal as the flash point test but is more prescriptive. The fuel dilution test determines the percent by volume of fuel and water. The analysis can determine the cause of the change in flash point without having to conduct additional tests. Corrective actions, if required, could be implemented on a timelier basis. For oil systems not associated with internal combustion engines, lubricating oil flash point change in unlikely.

Enhancements

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

Attributes Affected	Enhancements
3. Parameters Monitored or Inspected	IP2: Revise appropriate procedures to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with oil analysis for other site diesel generators.
3. Parameters Monitored or Inspected	Revise appropriate procedures to sample and analyze generator seal oil and turbine hydraulic control oil (electrohydraulic fluid).
2. Preventive Actions 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria 7. Corrective Actions	Revise appropriate procedures to formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the program. The controlled documents will specify corrective actions in the event acceptance criteria are not met.
5. Monitoring and Trending	Revise appropriate procedures to formalize trending of preliminary oil screening results as well as data provided from independent laboratories.

Operating Experience

Analysis of oil samples taken in 1999 through 2006 from the containment spray pump motors showed that the lube oil in these motors was within normal tolerances and was satisfactory for continued use. Absence of particulates in a routine sampling program indicates a lack of corrosion, thus providing evidence that the program is effective in managing aging effects. Absence of contaminants provides an indication that the program is effective in preserving an environment that is not conducive to loss of material, cracking or fouling.

Analysis of an oil sample from a safety injection pump in April 2001 revealed moderate amounts of particulate and contaminates. Analysis performed on an oil sample from an RCP lower bearing in November 2002 indicated a high particulate level. In each case, the lube oil for these pumps was replaced on a priority basis. Use of warning level indicators to direct corrective actions prior to equipment degradation provides evidence that the program is effective in managing aging effects.

Oil analysis results for samples from an EDG in April and May 2002 indicated increasing wear metals concentrations. IP3 diesel fire pump engine crankcase oil analysis results in June 2003 indicated a trend of elevated wear metals. In each case, the lube oil was replaced and appropriate corrective actions were taken. Total acid numbers and viscosity levels from oil samples from service water pump motors in 2006 met pre-established warning levels. A 2006 sample of lube oil from a safety injection pump motor also indicated a high total acid number. Based on this data, the motor lube oil was replaced prior to component degradation. Use of warning level indicators to initiate performance of corrective actions prior to equipment degradation provides assurance that the program is effective in managing aging effects.

In June 2006, the practices for oil analysis were compared among all Entergy Nuclear Northeast sites. An action plan was developed to establish common oil sampling frequencies and analysis techniques based on best practices among the sites. Comparison of program techniques and development of fleet-standard practices provide assurance that the program will remain effective for managing aging effects for passive components.

Conclusion

The Oil Analysis Program has been effective at managing aging effects. The Oil Analysis Program assures the effects of aging are managed such that applicable components will continue to perform their intended function consistent with the current licensing basis through the period of extended operation.

B.1.27 ONE-TIME INSPECTION

Program Description

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

The elements of the program include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of any aging degradation. The program will include activities to confirm the absence of aging effects as described below.

A one-time inspection activity is used to verify the effectiveness of the water chemistry control programs by confirming that unacceptable cracking, loss of material, and fouling is not occurring on components within systems covered by water chemistry control programs.

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

A one-time inspection activity is used to verify the effectiveness of the Diesel Fuel Monitoring Program by confirming that unacceptable loss of material and fouling is not occurring on components within systems covered by the Diesel Fuel Monitoring Program.

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

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

- Internal surfaces of stainless steel valve bodies in the station air containment penetration exposed to condensation
- Internal surfaces of stainless steel piping, strainers, strainer housings, tanks, tubing and valve bodies exposed to condensation in the emergency diesel generator (EDG) starting air subsystem
- Internal surfaces of the carbon steel tanks, piping and valve bodies and stainless steel drain pans and flex hoses in the RCP oil collection system
- Internal surfaces of auxiliary feedwater system stainless steel tubing and valve bodies exposed to treated water (city water)
- Internal surfaces of stainless steel piping and valve bodies in the containment penetration for gas analyzers exposed to condensation
- Internal surfaces of circulating water (CW) system stainless steel or CASS components containing raw water

IP2

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

- Internal surfaces of the water treatment plant (WTP) system stainless steel components containing treated water (city water)

IP3

- Internal surfaces of the ammonia/morpholine addition (AMA) system stainless steel components containing treated water
- Internal surfaces of the boron and layup chemical addition (BLCA) system stainless steel components containing treated water
- Internal surfaces of city water makeup (CWM) system stainless steel and CASS components containing treated water (city water)
- Internal surfaces of the gaseous waste disposal (GWD) system CASS components containing condensation
- Internal surfaces of the hydrazine addition (HA) system stainless steel components containing treated water
- Internal surfaces of the liquid waste disposal (LWD) system stainless steel and CASS components containing raw water or treated water (city water)
- Internal surfaces of the nuclear equipment drain (NED) system stainless steel components containing raw water

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

When evidence of an aging effect is revealed by a one-time inspection, routine evaluation of the inspection results will identify appropriate corrective actions.

The inspection will be performed prior to the period of extended operation.

NUREG-1801 Consistency

The One-Time Inspection Program will be consistent with the program described in NUREG-1801, Section XI.M32, One-Time Inspection.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The One-Time Inspection Program is a new program. Plant and industry operating experience will be considered when implementing this program. The scope of the inspections and inspection techniques are consistent with proven industry practices for managing the effects of aging.

The One-Time Inspection Program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, operating experience assures that implementation of the One-Time Inspection Program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Conclusion

The One-Time Inspection Program provides assurance that the Water Chemistry Control, Diesel Fuel Monitoring, and Oil Analysis programs will be effective in managing the effects of aging to ensure component intended functions can be maintained in accordance with the current licensing basis (CLB) through the period of extended operation. In addition, the One-Time Inspection Program will confirm the absence of significant aging effects on specific system components where significant aging effects are not expected.

B.1.28 ONE-TIME INSPECTION – SMALL BORE PIPING

Program Description

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 ASME Code does not require volumetric examination of Class 1 small bore piping. The IPEC One-Time Inspection of ASME Code Class 1 Small Bore Piping Program will manage cracking through the use of volumetric examinations.

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.

When evidence of an aging effect is revealed by a one-time inspection, evaluation of the inspection results will identify appropriate corrective actions.

The NUREG-1801 Program Description for Program XI.M35 describes the program to include piping "less than or equal to NPS 4" " with a reference to ASME Section XI, Table IWB-2500-1, Examination Category BJ. However, according to ASME Code, a volumetric examination is already required for piping equal to NPS 4". Consistent with the Code, GALL Item IV.C2-1 applies the One-Time Inspection of ASME Code Class 1 Small Bore Piping Program (XI.M35) only to Class 1 piping less than NPS 4". Based on this, IPEC 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 considered consistent with GALL.

This inspection will be performed prior to the period of extended operation.

NUREG-1801 Consistency

The One-Time Inspection Program will be consistent with the program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The One-Time Inspection – Small Bore Piping Program is a new program. Plant and industry operating experience will be considered when implementing this program.

The One-Time Inspection – Small Bore Piping Program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, operating experience assures that implementation of the One-Time Inspection – Small Bore Piping Program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Conclusion

The One-Time Inspection – Small Bore Piping Program will be effective for managing aging effects. The One-Time Inspection – Small Bore Piping Program assures the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.29 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE

Program Description

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

Reactor building	Use visual or other NDE techniques to inspect the surface condition of carbon steel components of the reactor building cranes (polar and manipulator), crane rails, and girders, and refueling platform to manage loss of material. [existing]
Containment spray system	IP3: Perform wall thickness measurements of the NaOH tank to manage loss of material. [existing]
Safety injection system	Perform operability testing to manage fouling for recirculation pump motor cooling coils. Use visual or other NDE techniques to inspect the recirculation pump cooler housing to manage loss of material.
City water system	Use visual or other NDE techniques to inspect a representative sample of the internals of city water components exposed to treated water (city water) to manage loss of material.
Chemical and volume control system	During quarterly surveillances perform visual inspection of the external surface of charging pump casings to manage cracking. [existing]
Plant drains	Use visual or other NDE techniques to inspect a representative sample of the internals of carbon steel plant drain components to manage loss of material. IP2: Use visual or other NDE techniques to inspect the internals of backwater valves to manage loss of material. [existing]

Station air system	Use visual or other NDE techniques to inspect a representative sample of carbon steel station air containment penetration piping to manage loss of material.
Heating, ventilation, and air conditioning (HVAC) systems	Visually inspect and manually flex a representative sample of the HVAC duct flexible connections to manage cracking and change in material properties.
	Visually inspect portable blowers stored for emergency ventilation use.
	Visually inspect flexible trunks stored for emergency ventilation use.
Emergency diesel generators	Use visual or other NDE techniques to inspect a representative sample of EDG exhaust gas components to manage loss of material.
	Visually inspect both inside and outside surfaces of elastomer duct flexible connections on the intake portion of EDG duct.
	Use visual or other NDE techniques to inspect a representative sample of EDG air intake and aftercooler components to manage fouling and loss of material.
	Use visual or other NDE techniques to inspect a representative sample of EDG starting air components to manage loss of material.
	Use visual or other NDE techniques to inspect EDG cooling water makeup supply valves to manage loss of material.
Security generator system	Use visual or other NDE techniques to inspect a representative sample of security generator exhaust components to manage loss of material on internal surfaces.
	Use visual or other NDE techniques to inspect the surface condition of the radiator tubes and fins to manage loss of material on external surfaces. [existing]

IP2 SBO/Appendix R Diesel Generator	Use visual or other NDE techniques to inspect internal surfaces of a representative sample of diesel exhaust gas components to manage cracking and loss of material on internal surfaces. Use visual or other NDE techniques to inspect the internal surface condition of the engine turbocharger and aftercooler housing including external surfaces of tubes and fins to manage loss of material and fouling. Use visual or other NDE techniques to inspect the internal surfaces of the jacket water heat exchanger carbon steel bonnet and stainless steel tubes exposed to treated water (city water).
Fuel oil system	IP2: Use visual or other NDE techniques to inspect the fuel oil cooler for the SBO/Appendix R diesel generator to manage fouling. Use visual or other NDE techniques to inspect internal and external surfaces of the emergency fuel oil trailer transfer tank and associated valves for loss of material.
IP3 Appendix R Diesel Generator	Use visual or other NDE techniques to inspect a representative sample of diesel exhaust components to manage cracking and loss of material on internal surfaces. [existing] Visually inspect the radiator to manage fouling. [existing] Use visual or other NDE techniques to inspect the aftercooler to manage fouling and loss of material. [existing] Use visual or other NDE techniques to inspect a representative sample of starting air components to manage loss of material. [existing] Use visual or other NDE techniques to inspect a representative sample of crankcase exhaust subsystem components to manage loss of material. [existing]
Auxiliary Feedwater	Use visual or other NDE techniques to inspect a representative sample of copper alloy and carbon steel components to manage loss of material.

Containment Cooling and Filtration	Visually inspect both internally and externally and manually flex a representative sample of duct flexible connections to manage cracking and change in material properties. Inspect components inside the each fan cooling unit including damper housings, filter housings, moisture separators, and heat exchanger headers, housings, and tubes for loss of material.
Control Room HVAC	Visually inspect a representative sample of control room HVAC air cooled condensers and evaporators to manage loss of material and fouling. Visually inspect a representative sample of control room HVAC ducts and drip pans to manage loss of material. Visually inspect and manually flex a representative sample of duct flexible connections to manage cracking and change in material properties.

Nonsafety-related systems affecting IP2 safety-related systems	Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of circulating water system carbon steel and copper alloy components to manage loss of material. Use visual or other NDE techniques to inspect inside and outside surfaces of a representative sample of circulating water system elastomer flexible piping connections to manage loss of material and cracking and change in material properties. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of city water gray cast iron, carbon steel, and copper alloy components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of intake structure system carbon steel components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of emergency diesel generator carbon steel components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of fresh water cooling copper alloy and carbon steel components to manage loss of material.

Nonsafety-related systems affecting IP2 safety-related systems (cont.)	Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of instrument air system carbon steel components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of integrated liquid waste handling system carbon steel components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of lube oil system carbon steel components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of miscellaneous system carbon steel components to manage loss of material. Use visual or other NDE techniques to inspect the inside surface of the pressurizer relief tank to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of radiation monitoring system carbon steel components to manage loss of material. Use visual or other NDE techniques to inspect a representative sample of river water service system carbon steel and gray cast iron components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of station air system carbon steel and copper alloy components to manage loss of material. Use visual or other NDE techniques to inspect a representative sample of waste disposal system carbon steel components to manage loss of material. Use visual or other NDE techniques to inspect a representative sample of water treatment plant carbon steel and gray cast iron components to manage loss of material.

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

Nonsafety-related systems affecting IP3 safety-related systems (cont)	Use visual or other NDE techniques to inspect a representative sample of station air system carbon steel components to manage loss of material. Use visual or other NDE techniques to inspect the inside surfaces of a representative sample of steam generator sampling carbon steel components to manage loss of material. Use visual or other NDE techniques to inspect a representative sample of secondary plant sampling system carbon steel components to manage loss of material.

Evaluation

1. Scope of Program

The IPEC Periodic Surveillance and Preventive Maintenance Program, with regard to license renewal, includes those tasks credited with managing aging effects identified in aging management reviews.

2. Preventive Actions

Inspection and testing activities used to identify component aging effects do not prevent aging effects. However, activities are intended to prevent failures of components that might be caused by aging effects.

3. Parameters Monitored or Inspected

This program provides instructions for monitoring structures, systems, and components to detect degradation. Inspection and testing activities monitor various parameters including system temperatures, wall thickness, surface condition, and signs of cracking.

4. Detection of Aging Effects

Preventive maintenance activities provide for inspections to detect aging effects. Periodic surveillances provide for testing to detect aging effects. Inspection and testing intervals are established such that they provide timely detection of degradation. Inspection and testing intervals are dependent on component material and environment and take into consideration industry and plant-specific operating experience and manufacturers' recommendations. Each inspection or test occurs at least once every five years with the exception of the following.

- Components associated with emergency and Appendix R diesel generators are inspected every six years in accordance with manufacturer recommendations.
- Appendix R diesel generator crankcase exhauster inspection is every ten years in accordance with manufacturer recommendations.
- Copper alloy components exposed to city water are inspected every ten years since city water is treated per New York State requirements and aging effects are not expected.
- The internals of each pressurizer relief tank are inspected every ten years since the tank is coated.

The extent and schedule of inspections and testing assure detection of component degradation prior to loss of intended functions. Established techniques such as visual inspections or NDE are used.

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

The program provides for increasing inspection sample size in the event that aging effects are detected. Unacceptable inspection findings are evaluated in accordance with the IPEC corrective action process to determine the need for accelerated inspection frequency and for monitoring and trending the results.

5. Monitoring and Trending

Preventive maintenance and surveillance testing activities provide for monitoring and trending of aging degradation.

6. Acceptance Criteria

Periodic Surveillance and Preventive Maintenance Program acceptance criteria are defined in specific inspection and testing procedures. Acceptance criteria include appropriate temperature, no significant wear, corrosion, cracking, change in material properties (for elastomers), and significant fouling based on applicable intended functions established by plant design basis.

7. Corrective Actions

Corrective actions for this program are administered under the site QA program which meets requirements of 10 CFR Part 50, Appendix B.

8. Confirmation Process

This attribute is discussed in Section B.0.3.

9. Administrative Controls

This attribute is discussed in Section B.0.3.

10. Operating Experience

Typical inspection results of this program include:

- IP2 reactor building polar crane (May 2006): no indication of corrosion, cracking, or wear in the crane structural members.
- IP3 reactor building polar crane (February 2001 and March 2005): no indication of corrosion, cracking, or wear in the crane structural members.
- IP3 sodium hydroxide (NaOH) storage tank (August 2004): no deficiencies. Ultrasonic measurement of wall thickness was satisfactory.
- IP2 and IP3 recirculation pumps and related system components (2005 and 2006): no deficiencies.
- IP2 Diesel Generator Building floor drain backwater valves (October 2006): no loss of material.
- IP2 and IP3 EDG's (2005 and 2006): no unacceptable loss of material.
- Security Generator (January 2002 and December 2005): no significant corrosion or wear.
- IP3 Appendix R diesel generator (September 2006 and December 2006): no significant corrosion or wear.

The use of proven monitoring techniques and acceptance criteria provides assurance that this program will remain effective for managing aging effects for passive components.

Enhancements

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

Attributes Affected	Enhancements
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Program activity guidance documents will be developed or revised as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Conclusion

The Periodic Surveillance and Preventive Maintenance Program is effective for managing aging effects since it consists of proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls. The Periodic Surveillance and Preventive Maintenance Program assures the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.30 REACTOR HEAD CLOSURE STUDS

Program Description

The Reactor Head Closure Studs Program is an existing program that includes inservice inspection (ISI) in conformance with the requirements of ASME Section XI, Subsection IWB, and preventive measures (e.g., rust inhibitors, stable lubricants, appropriate materials) to mitigate cracking and loss of material of reactor head closure studs, nuts, washers, and bushings.

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. Therefore, use of different ASME Code Editions for this program is not considered an exception to NUREG-1801.

NUREG-1801 Consistency

The Reactor Head Closure Studs Program is consistent with the program described in NUREG-1801, Section XI.M3, Reactor Head Closure Studs.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

ISI-IWB examinations at IP2 and IP3 were conducted during 2004 and 2005. Results found to be outside of acceptable limits were repaired, replaced, or evaluated in accordance with ASME Section XI requirements. Identification of degradation and corrective action prior to loss of intended function provide assurance that the program is effective for managing aging effects.

A self-assessment of the ISI program was completed in October 2004. Review of the scope for 2R16 (2004) and 3R13 (2005) verified that the proper inspection percentages had been planned for both outages. A follow-up assessment was held for IP2 in March 2006 to ensure that all inspection activities required to close out the third 10-year ISI interval were scheduled for 2R17. Confirmation of compliance to program requirements provides assurance that the program will remain effective for managing loss of material of components.

QA surveillances in 2005 and 2006 revealed no issues or findings that could impact effectiveness of the program.

Conclusion

The Reactor Head Closure Studs Program has been effective at managing aging effects. The Reactor Head Closure Studs Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.31 REACTOR VESSEL HEAD PENETRATION INSPECTION

Program Description

The Reactor Vessel Head Penetration Inspection Program is an existing program that manages primary water stress corrosion cracking (PWSCC) of nickel-based alloy reactor vessel head penetrations exposed to borated water to ensure that the pressure boundary function is maintained. 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.

IPEC will continue to implement commitments associated with (1) NRC Orders, Bulletins and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines.

NUREG-1801 Consistency

The Reactor Vessel Head Penetration Inspection Program is consistent with the program described in NUREG-1801, Section XI.M11A, Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

Bare metal visual examination of no less than 95 percent of the IP2 reactor vessel head surface and 360 degrees around each head penetration nozzle was completed during November 2004 (2R16), consistent with the requirements of NRC Order EA-03-009 and approved relaxation request. There were no indications of reactor vessel head degradation or leakage due to cracking.

Bare metal visual examination of no less than 95 percent of the IP3 reactor vessel head surface and 360 degrees around each head penetration nozzle was completed during March 2005 (3R13), consistent with the requirements of NRC Order EA-03-009 and approved relaxation requests. There were no indications of reactor vessel head degradation or leakage due to cracking. A QA surveillance of these inspections found that all regulatory requirements were met.

The most recent inspection of the IP2 reactor vessel head penetrations was completed in May 2006 (2R17). The procedure used was written as a result of lessons learned during conduct of the 2R16 and 3R13 inspections. The results of this 2R17 inspection were satisfactory. Bare metal areas reviewed during this inspection were noted to have a significant improvement in the cleanliness in the base metal and annulus around the penetrations. A QA surveillance of these inspections found that all regulatory requirements were met. A self-assessment of the inspection process identified improvements that should be made before the process is used in the future. Corrective actions were taken to implement these process improvements. Absence of cracking, along with continuous improvement of material condition, provides assurance that the program is effective for managing aging effects. Use of recent OE and industry guidance in the development of site-wide procedures, along with site QA oversight and continuous process improvement, provide assurance that the program will remain effective for managing aging effects for passive components.

<u>Conclusion</u>

The Reactor Vessel Head Penetration Inspection Program has been effective at managing aging effects. The Reactor Vessel Head Penetration Inspection Program assures the aging effects are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.32 REACTOR VESSEL SURVEILLANCE

Program Description

The Reactor Vessel Surveillance Program is an existing program that manages reduction in fracture toughness of reactor vessel beltline materials to assure that the pressure boundary function of the reactor pressure vessel is maintained through the period of extended operation. The program is based on ASTM E-185, "Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels", as required by 10 CFR 50 Appendix H, and includes an evaluation of radiation damage based on pre- and post-irradiation testing of Charpy V-notch and tensile specimens. Irradiation of the specimens will be higher than the irradiation of the vessel because the specimens are closer to the core than the vessel itself.

Under the Reactor Vessel Integrity Program, reports are submitted as required by 10 CFR Part 50 Appendix H. Reports include a capsule withdrawal schedule, a summary report of capsule withdrawal and test results and, if needed, a Technical Specification change for pressure-temperature limit curves.

The program meets the recommendations of ASTM E-185 and complies with 10 CFR Part 50, Appendix H. The program includes an evaluation of radiation damage based on pre and post-irradiation testing of Charpy V-notch and tensile specimens from the most limiting plate used in the core region of the reactor vessel.

NUREG-1801 Consistency

The Reactor Vessel Surveillance Program is consistent with the program described in NUREG-1801, Section XI.M31, Reactor Vessel Surveillance with an enhancement.

Exceptions to NUREG-1801

None

Enhancements

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

Attributes Affected	Enhancements
5. Monitoring and Trending	The specimen capsule withdrawal schedules will be revised to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation. Appropriate procedures will be revised to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.

Operating Experience

An updated reactor vessel surveillance capsule withdrawal schedule for IP2 was submitted to the NRC in November 2004. Information from the surveillance program throughout the operating history of IP2 was included in this request to change the previous schedule. The NRC staff determined that the new withdrawal schedule met the criteria in ASTM E-185-82 and was in compliance with 10CFR50 Appendix H. Review of the surveillance requirements against industry standards, confirmed through NRC oversight, provides assurance that the program will remain effective in managing reduction in fracture toughness of reactor vessel beltline materials.

A summary of IP3 surveillance capsule exposure evaluations was prepared in November 2003 during the fluence evaluation for power uprate. This was used to provide projections of the neutron exposure of the reactor vessel for future operating periods at the uprated power level. The surveillance capsule lead factors provided in this calculation will be used as the basis for development of future capsule withdrawal schedules. Review of the surveillance program with respect to the changes created by the power uprate provides assurance that the program will remain effective in managing reduction in fracture toughness of reactor vessel beltline materials.

Conclusion

The Reactor Vessel Surveillance Program has been effective at managing aging effects. The Reactor Vessel Surveillance Program assures the aging effects are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.33 SELECTIVE LEACHING

Program Description

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

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

NUREG-1801 Consistency

The Selective Leaching Program will be consistent with the program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Selective Leaching Program is a new program. Plant and industry operating experience will be considered when implementing this program. Industry operating experience that forms the basis for the program is described in the operating experience element of the NUREG-1801 program description. IPEC plant-specific operating experience is not inconsistent with the operating experience in the NUREG-1801 program description.

The IPEC program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, operating experience provides assurance that implementation of the Selective Leaching Program will manage aging effects such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extend operation.

Conclusion

The Selective Leaching Program will be effective for managing aging effects since it will incorporate proven monitoring techniques. The Selective Leaching Program assures the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.34 SERVICE WATER INTEGRITY

Program Description

The Service Water Integrity Program is an existing program that relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the service water system are managed through the period of extended operation. The program includes component inspections for erosion, corrosion, and biofouling to verify the heat transfer capability of safety-related heat exchangers cooled by service water. Chemical treatment using biocides and sodium hypochlorite and periodic cleaning and flushing of infrequently used loops are methods used to control fouling within the heat exchangers and to manage loss of material in service water components.

NUREG-1801 Consistency

The Service Water Integrity Program is consistent with the program described in NUREG-1801, Section XI.M20, Open-Cycle Cooling Water System.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

In July 2003, a peer assessment of the IP3 service water program was conducted by EPRI. Some areas for improvement were identified. Corrective actions taken include changes to chlorination practices and evaluation of new software tools for heat exchanger performance analysis. Assessment of existing practices by offsite review groups, followed by appropriate corrective action, provides assurance that the program will remain effective for managing aging effects for passive components.

Self-assessments of the IP2 and IP3 ultimate heat sink (GL 89-13 Program) were performed in April 2004 and June 2005. The focus of the self-assessment was to ensure that ultimate heat sink subcomponents are adequately maintained and operate within plant design basis. Identification of program weaknesses, and subsequent corrective actions, provide assurance that the program will remain effective for managing loss of material of components.

In December 2005, NRC completed an ultimate heat sink performance review at IP2 to verify that Entergy was monitoring performance of the instrument air closed cooling water heat exchangers on a continuing basis and to ensure that any potential deficiencies which could mask degraded performance were identified. The inspectors reviewed the design basis documents and Final

Safety Analysis Report (FSAR) to validate that testing acceptance criteria were appropriate. The inspectors also reviewed the latest inspection reports for the heat exchangers, evaluated the results of eddy current testing, and ensured that the appropriate tube plugging criteria were used. In addition, the inspectors verified that Entergy was maintaining their commitments from Generic Letter 89-13 concerning heat exchanger inspection and testing. No findings of significance were identified. Confirmation of program compliance with established standards and regulations provides assurance that the program will remain effective for managing loss of material of components.

As part of the ultimate heat sink performance review at IP3 in 2005, NRC observed the condition of a component cooling water (CCW) heat exchanger after it was opened for periodic inspection and cleaning. The inspectors observed and reviewed maintenance activities of this safety-related heat exchanger inspection and cleaning to assess the adequacy of preventive maintenance to minimize the effects of biofouling on heat exchanger performance. The inspectors visually examined the heat exchanger when it was first opened to assess the adequacy of Entergy's periodic cleaning to avoid excessive fouling. The inspectors also reviewed the as-found eddy current testing results and compared it to previous testing data. No findings of significance were identified. Reviews of program specifics provide evidence that the program is effective for managing loss of material of components.

In June 2006, NRC completed an ultimate heat sink performance review at IP3 to verify that Entergy was using the periodic maintenance method outlined in Electric Power Research Institute (EPRI) document NP-7552, "Heat Exchanger Performance Monitoring Guidelines" for the Unit 3 EDG lube oil coolers. The inspector reviewed the results of the last inspections and eddy current tests for each of the lube oil coolers. No findings of significance were identified. Confirmation of program compliance with established standards and regulations provides assurance that the program will remain effective for managing loss of material of components.

In June 2006, NRC completed an ultimate heat sink performance review at IP3 to verify that Entergy was using the periodic maintenance method outlined in Electric Power Research Institute (EPRI) document NP-7552, "Heat Exchanger Performance Monitoring Guidelines" for the Unit 3 EDG lube oil coolers. The inspector reviewed the results of the last inspections and eddy current tests for each of the lube oil coolers. No findings of significance were identified. Confirmation of program compliance with established standards and regulations provides assurance that the program will remain effective for managing loss of material of components.

In June 2006, NRC completed an ultimate heat sink performance review at IP2 which included the component cooling water heat exchangers and the EDG jacket water and lube oil heat exchangers. The inspector reviewed documents to ensure that potential common cause heat sink performance problems that had the potential to increase risk were identified and corrected by Entergy. The inspector also reviewed records to ensure that potential macro fouling (silt, debris, etc.) issues and biofouling issues were closely examined by Entergy. To ensure adequate implementation of NRC Generic Letter 89-13, the inspector reviewed Entergy's inspection, cleaning, and eddy current testing methods and frequency with the responsible system engineers. The inspector compared surveillance test and inspection data, including as-found conditions and eddy current summary sheets, to the established acceptance criteria to verify that the results were acceptable and that system heat exchanger operation was consistent with design. The inspector reviewed heat exchanger design basis values and assumptions, plugging limit calculations, and vendor information to verify that they were incorporated into the heat exchanger inspection and maintenance procedures. The inspector reviewed a sample of condition reports related to the component cooling water and emergency diesel generator heat exchangers, and the service water system to ensure that Entergy was appropriately identifying, characterizing, and correcting problems related to these systems and components. No findings of significance were identified. Confirmation of program compliance with established standards and regulations provides assurance that the program will remain effective for managing loss of material of components.

Conclusion

The Service Water Integrity Program has been effective at managing aging effects. The Service Water Integrity Program assures the effects of aging are managed such that applicable components will continue to perform their intended function consistent with the current licensing basis through the period of extended operation.

B.1.35 STEAM GENERATOR INTEGRITY

Program Description

The Steam Generator Integrity Program is an existing program. In the industry, steam generator (SG) tubes have experienced tube degradation related to corrosion phenomena, such as primary water stress corrosion cracking (PWSCC), outside diameter stress corrosion cracking (ODSCC), intergranular attack (IGA), pitting, and wastage, along with other mechanically induced phenomena, such as denting, wear, impingement damage, and fatigue. Nondestructive examination (NDE) techniques are used to identify tubes that are defective and need to be removed from service or repaired in accordance with the guidelines of the plant technical specifications.

The Steam Generator Integrity Program includes processes for monitoring and maintaining secondary side component integrity. The program defines when inspections and maintenance are performed, the scope of work, and the methods used. The Steam Generator Integrity Program is implemented in accordance with NEI 97-06, "Steam Generator Program Guidelines."

NUREG-1801 Consistency

The Steam Generator Integrity Program is consistent with the program described in NUREG-1801, Section XI.M19, Steam Generator Tube Integrity with enhancement.

Exceptions to NUREG-1801

None

Enhancements

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

Attributes Affected	Enhancements
5. Monitoring and Trending	Revise appropriate procedures to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.

Operating Experience

IP2 steam generators were replaced in December 2000 and began operating at uprated power levels in November 2004. IP3 steam generators were replaced in 1989 and began operating at uprated power levels in April 2005.

An IP3 SG degradation assessment completed in March 2003, per the provisions of NEI 97-06 Revision 1 and the EPRI PWR Steam Generator Examination Guidelines Revision 5 (EPRI TR-107569), summarized the inspection results of IP3 replacement steam generators since their installation in 3R7 (1989), compared this to industry OE, and described a 3R12 (2003) inspection plan based on this input. Use of unit-specific OE, industry OE, and industry guidance in the development of an inspection plan provide assurance that the program will be effective for managing aging effects for passive components.

Inspections of the IP3 steam generators were conducted in March 2003 (3R12). All indications in these inspections were below the calculated integrity limits provided in the pre-outage degradation assessment. During these 3R12 inspections, NRC inspectors evaluated the SG integrity assessment program, and compared it with the NRC accepted guidance contained in the EPRI PWR Steam Generator Examination Guidelines Revision 5 (EPRI TR-107569). To evaluate how the SG assessment program was implemented, the NRC inspectors witnessed SG tube testing and secondary side inspection processes. No findings of significance were identified. Confirmation of program compliance with established standards and regulations provides assurance that the program is effective for managing aging of passive components.

In June 2005, the IP2 program procedure was revised to incorporate the results of the September 2004 INPO Steam Generator Review Visit. In July 2005, the IP3 program procedure was revised to incorporate the latest EPRI guidelines. Review of existing practices by industry groups, implementation of process improvements, and incorporation of industry guidelines provides assurance that the program will remain effective for managing aging effects for passive components.

An INPO-assisted self-assessment of the IP2 and IP3 steam generator programs was performed in September 2004. Actions were generated that led to program improvement in several key areas. Identification of program weaknesses, and subsequent corrective actions, provide assurance that the program will remain effective for managing loss of material of components

An IP2 steam generator degradation assessment completed in April 2006, per the provisions of NEI 97-06 Revision 1 and the EPRI PWR Steam Generator Examination Guidelines Revision 5 (EPRI TR-107569), summarized the inspection results of IP2 replacement steam generators since their installation in December 2000, compared this to industry OE, and listed a 2R17 (2006) inspection plan based on this input. Use of unit-specific OE, industry OE, and industry guidance in the development of an inspection plan provide assurance that the program will remain effective for managing aging effects for passive components.

Inspections of the IP2 steam generators were conducted in April 2006 (2R17). All indications in these inspections were below the calculated integrity limits provided in the pre-outage degradations assessment. Absence of unacceptable degradation provides evidence that the program is effective for managing loss of material of components.

In April 2006 (2R17), NRC reviewed portions of the steam generator management plan, degradation assessment, and the final operational assessment to evaluate the steam generator inspection and management program. The inspector reviewed plant specific steam generator information, tube inspection criteria, integrity assessments, degradation modes, and tube plugging criteria. Entergy conducted eddy current testing of tubes in all steam generators to identify and quantify tube degradation mechanisms and to confirm tube integrity following the completion of two fuel cycles of operation. The inspector observed a sample of tubes examined from each generator to verify Entergy's examination of the entire length. No findings of significance were identified. Confirmation of program compliance with established standards and regulations provides assurance that the program is effective for managing aging of passive components.

<u>Conclusion</u>

The Steam Generator Integrity Program assures the effects of aging are managed such that applicable components will continue to perform their intended function consistent with the current licensing basis through the period of extended operation.

B.1.36 STRUCTURES MONITORING

Program Description

The 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 structures and structural components to ensure there is no loss of intended function.

Since protective coatings are not relied upon to manage the effects of aging for structures included in the Structures Monitoring Program, the program does not address protective coating monitoring and maintenance.

NUREG-1801 Consistency

The Structures Monitoring Program is consistent with the program described in NUREG-1801, Section XI.S6, Structures Monitoring Program, with enhancements.

Exceptions to NUREG-1801

None

Enhancements

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

Attributes Affected	Enhancements
1. Scope of Program	Appropriate procedures will be revised to explicitly specify that the following structures are included in the program. • Appendix R emergency diesel generator foundation (IP3) • Appendix R emergency diesel generator fuel oil tank vault (IP3) • Appendix R emergency diesel generator switchgear and enclosure (IP3) • city water storage tank foundation • condensate storage tanks foundation (IP3) • containment access facility and annex (IP3)

Attributes Affected	Enhancements
	• discharge canal (IP2/3) • emergency lighting poles and foundations (IP2/3) • fire pumphouse (IP2) • fire protection pumphouse (IP3) • fire water storage tank foundation (IP2/3) • gas turbine 1 fuel storage tank foundation • maintenance and outage building–elevated passageway (IP2) • new station security building (IP2) • nuclear service building (IP1) • primary water storage tank foundation (IP3) • refueling water storage tank foundation (IP3) • security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • superheater stack • transformer/switchyard support structures (IP2) • waste holdup tank pit (IP2/3)

Attributes Affected	Enhancements
1. Scope of Program	Appropriate procedures will be revised to clarify that in addition to structural steel and concrete, the following commodities are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails, and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches, and hatch covers • monorails • new fuel storage racks • sumps, sump screens, strainers and flow barriers
1. Scope of Program 4. Detection of Aging Effects	Guidance will be added to the Structures Monitoring Program to inspect inaccessible concrete areas that are exposed by excavation for any reason. IPEC will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring.
4. Detection of Aging Effects	Revise applicable structures monitoring procedures for inspection of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material.

Attributes Affected	Enhancements
4. Detection of Aging Effects	Guidance to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years) will be added to the Structures Monitoring Program. IPEC will obtain samples from a well that is representative of the ground water surrounding below-grade site structures. Samples will be monitored for sulfates, pH and chlorides.

Operating Experience

Inspections of structural steel, concrete exposed to fluid, and structural elastomers from 2001 through 2005 revealed signs of degradation such as cracks, gaps, and corrosion (rust). Identification of degradation and corrective action prior to loss of intended function provide assurance that the program is effective for managing aging effects for structural components.

Structural monitoring of concrete structures and components from 2001 through 2006 revealed minor cracks that did not affect the structural integrity of the components. Monitoring of structural steel members revealed minor corrosion only. Inspection intervals were adjusted as necessary to ensure future inspections identify degradation prior to loss of intended function. Identification of degradation and corrective action prior to loss of intended function provide assurance that the program is effective for managing aging effects for structural components.

Conclusion

The Structures Monitoring Program has been effective at managing aging effects. The Structures Monitoring Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.37 THERMAL AGING EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL (CASS)

Program Description

The Thermal Aging Embrittlement of CASS Program is a new program that augments the inspection of the reactor coolant system components in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI. The inspection detects the effects of loss of fracture toughness due to thermal aging embrittlement of cast austenitic stainless steel (CASS) components. This aging management program determines the susceptibility of CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. The program provides aging management through either enhanced volumetric examination or flaw tolerance evaluation. Additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required for components that are not susceptible to thermal aging embrittlement.

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

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

NUREG-1801 Consistency

The Thermal Aging Embrittlement of CASS Program will be consistent with the program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Thermal Aging Embrittlement of CASS Program is a new program. Plant and industry operating experience will be considered when implementing this program. Industry operating experience that forms the basis for the program is described in the operating experience element of the NUREG-1801 program description. IPEC plant-specific operating experience is not inconsistent with the operating experience in the NUREG-1801 program description.

The Thermal Aging Embrittlement of CASS Program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, operating experience assures the implementation of the Thermal Aging Embrittlement of CASS Program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Conclusion

The Thermal Aging Embrittlement of CASS Program will use existing techniques with demonstrated capability and a proven industry record to assure the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.38 THERMAL AGING AND NEUTRON IRRADIATION EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL (CASS)

Program Description

The Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is a new program that augments the reactor vessel internals visual inspection in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, Subsection IWB. This inspection manages the effects of loss of fracture toughness due to thermal aging and neutron embrittlement of cast austenitic stainless steel (CASS) components. This aging management program determines the susceptibility of CASS components to thermal aging or neutron irradiation (neutron fluence) embrittlement based on casting method, molybdenum content, operating temperature and percent ferrite. For each "potentially susceptible" component, aging management is accomplished through either a component-specific evaluation or a supplemental examination of the affected component as part of the inservice inspection (ISI) program during the license renewal term.

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

NUREG-1801 Consistency

The Thermal Aging and Neutron Irradiation Embrittlement of CASS Program will be consistent with the program described in NUREG-1801, Section XI.M13, Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is a new program. Plant and industry operating experience will be considered when implementing this program. Industry operating experience that forms the basis for the program is described in the operating experience element of the NUREG-1801 program description. IPEC plant-specific operating experience is not inconsistent with the operating experience in the NUREG-1801 program description.

The Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, operating experience assures the implementation of the Thermal Aging and Neutron

Irradiation Embrittlement of CASS Program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Conclusion

The Thermal Aging and Neutron Irradiation Embrittlement of CASS Program will use existing techniques with demonstrated capability and a proven industry record to assure the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.39 WATER CHEMISTRY CONTROL – AUXILIARY SYSTEMS

Program Description

The Water Chemistry Control – Auxiliary Systems Program is an existing program that manages loss of material and cracking for components exposed to treated water.

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

The One-Time Inspection Program for Water Chemistry utilizes inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – Auxiliary Systems Program has been effective at managing aging effects.

Evaluation

1. Scope of Program

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

2. Preventive Actions

The program includes monitoring and control of treated water for components included in the scope of the program to minimize exposure to aggressive environments, thereby mitigating the effects of aging.

3. Parameters Monitored or Inspected

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

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

Stator cooling water is monitored for copper and conductivity monthly.

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

4. Detection of Aging Effects

The program manages loss of material and cracking for stainless steel carbon steel, and copper alloy components included in the scope of the program.

This is a mitigation program and does not provide for detection of aging effects. However, the One-Time Inspection Program [B.1.27] describes inspections planned to verify the effectiveness of water chemistry control programs to ensure that significant degradation is not occurring and component intended function is maintained during the period of extended operation.

5. Monitoring and Trending

Initially, analytical results are interpreted by the chemist performing the analysis. Abnormal trends in the chemistry data are evaluated by that person given the status of that system at that time. Any significant abnormality or trend, as well as out of specification or out of control band chemistry parameter is brought to the attention of the Shift Manager and Chemistry Management. Values from analyses are archived for long-term trending and review.

Trending is not required to predict the extent of degradation since maintaining parameters within acceptance criteria prevents degradation. OE indicates effectiveness in preventing aging effects if parameters are maintained within limits.

6. Acceptance Criteria

Acceptance criteria for the NaOH shipments are as follows.

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

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

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

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

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

7. Corrective Actions

Abnormal trends in the chemistry data are evaluated by chemistry personnel given the status of that system at that time. Any significant abnormality or trend, as well as out of specification or out of control band chemistry parameter is brought to the attention of the Shift Manager and Chemistry Management. If acceptance criteria are not met, chemistry parameters are adjusted as appropriate. Additional sampling and verification is performed if necessary. Unacceptable inspection results are evaluated and corrective actions are determined in accordance with the Corrective Action Program.

8. Confirmation Process

This attribute is discussed in Section B.0.3.

9. Administrative Controls

This attribute is discussed in Section B.0.3.

10. Operating Experience

QA audits of the chemistry control program in 2005 and 2006 found that compliance with all guidelines (INPO 03-004, EPRI TR-105714 and TR-102134) for chemistry performance was satisfactory, and that sufficient parameters are measured to detect abnormal conditions or changes to conditions. All chemistry parameters were found to be maintained within specified bands, and auxiliary systems were found to be treated and controlled to industry guidelines. Adherence to chemistry specifications provides assurance that the program will remain effective for managing the effects of aging.

Conclusion

The Water Chemistry Control – Auxiliary Systems Program has been effective at managing the effects of aging for components exposed to treated water. The Water Chemistry Control - Auxiliary Systems Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.40 WATER CHEMISTRY CONTROL – CLOSED COOLING WATER

Program Description

The Water Chemistry Control – Closed Cooling Water Program is an existing program that includes preventive measures that manage loss of material, cracking, or fouling for components in closed cooling water systems: component cooling water (CCW), instrument air closed cooling (IACC), emergency diesel generator cooling, SBO/Appendix R diesel generator cooling (IP2), Appendix R diesel generator cooling (IP3), security generator cooling, conventional closed cooling (CCC) (IP2 only), and turbine hall closed cooling (THCC) (IP3 only). These chemistry activities provide for monitoring and controlling closed cooling water chemistry using IPEC procedures and processes based on EPRI guidelines for closed cooling water issued as EPRI TR-1007820, Closed Cycle Cooling Water Chemistry, Rev. 1, dated April 2004. This guideline supersedes EPRI TR-107396, Closed Cycle Cooling Water Chemistry Guideline, Revision 0, issued November 1997, referenced in NUREG-1801. Differences in Revision 0 and Revision 1 are described below.

The purpose of Revision 0 was to assist plants in developing water treatment strategies to protect carbon-steel and copper-containing systems from corrosion. This revision does not provide precise direction, but instead provides broad direction for plants to develop their own closed cooling water chemistry control programs by utilizing the guidance in the report to tailor specific station programs. Revision 0 does not provide tables for "Control Parameters" and "Diagnostic Parameters" with respective sampling frequency and expected values. However, parameters that should be monitored are identified as "Control Parameters" or "Diagnostic Parameters." In general, Revision 0 allows plants a great deal of flexibility in developing their closed cooling water chemistry programs.

Revision 1 is significantly more directive and incorporates action levels with established thresholds for specific actions required. This revision specifically establishes recommended monitoring frequencies and clearly identifies expected parameter values. Revision 0 identifies total organic carbon, dissolved oxygen, total alkalinity, calcium/magnesium, and refrigerants as diagnostic, but these are not described in Revision 1. None of these parameters (or monitoring of them) is considered to have any effect on the long-term health of closed cycle cooling water systems.

Both the EPRI closed cycle cooling water guidelines make a clear distinction between "control parameters" and "diagnostic parameters." Adherence to control parameters is expected, whereas diagnostic parameters are suggested, but can be plant specific. Deviations from EPRI recommended diagnostic parameters are not considered exceptions to NUREG-1801.

Future revisions of the EPRI closed cycle cooling water guidelines will be adopted as required, commensurate with industry standards.

The One-Time Inspection Program for Water Chemistry utilizes inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – Closed Cooling Water Program has been effective at managing aging effects.

NUREG-1801 Consistency

The Water Chemistry Control – Closed Cooling Water Program is consistent with the program described in NUREG-1801, Section XI.M21, Closed-Cycle Cooling Water System, with exceptions and enhancements.

Exceptions to NUREG-1801

The Water Chemistry Control – Closed Cooling Water Program is consistent with the program described in NUREG-1801, Section XI.M21, Closed-Cycle Cooling Water System, with the following exceptions.

Attributes Affected	Exception
3. Parameters Monitored or Inspected	NUREG-1801 states the program monitors the effects of corrosion and SCC by testing and inspection in accordance with guidance in EPRI TR-107396. The IPEC Water Chemistry Control Closed Cooling Water Program does not perform performance and functional testing.[1]
4. Detection of Aging Effects	NUREG-1801 recommends the use of performance and functional testing to ensure acceptable function of the CCCW systems. The IPEC Water Chemistry Control – Closed Cooling Water Program does not perform performance and functional testing.[1]
5. Monitoring and Trending	NUREG-1801 recommends internal visual inspections and performance and functional tests periodically to demonstrate system operability. The IPEC Water Chemistry Control - Closed Cooling Water Program does not perform visual inspections, performance, and functional testing. [1]

6. Acceptance Criteria	NUREG-1801 recommends system and component performance test result evaluations. The IPEC Water Chemistry Control - Closed Cooling Water Program does not perform component performance and functional testing evaluations. [1]

Exception Note

1. While NUREG-1801, Section XI.M21, Closed-Cycle Cooling Water System endorses EPRI report TR-107396 for performance and functional testing guidance, EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in managing effects of aging on long-lived, passive CCW system components. Rather, EPRI report TR-107396 states in Section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In most cases, functional and performance testing verifies that component active functions can be accomplished and as such would be included as part of maintenance rule (10 CFR 50.65) programs. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control – Closed Cooling Water Program and One-time Inspection Program through monitoring and control of water chemistry parameters and verification of the absence of aging effects.

Enhancements

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

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

Operating Experience

In June 2003, it was noted that CCW corrosion inhibitor (molybdate concentration) had been out of specification 50% of the time since the new specification was issued in March 2003, due to dilution from water added to this system to compensate for leaks and work activities. Corrective action was taken to repair the leaks and perform a chemical addition to restore the molybdate concentration to specification. Identification of out-of-specification conditions and corrective action prior to loss of intended function provides assurance that the program will remain effective for managing aging effects for passive components. Subsequently, corrosion inhibitor concentration has been satisfactory.

A QA audit of the plant chemistry program was conducted in August 2003. This audit identified the control of closed cooling water chemistry at IP2 as one of the specific areas which had improved since the last audit. Continuous program improvement provides assurance that the program will remain effective for managing loss of material of components.

Reports of CCW chemistry control indicator (corrosion inhibitor and hardness) show that IP2 and IP3 CCW chemistry was within specification throughout 2006 except for part of May when the IP2 system was in maintenance status during 2R17. Adherence to chemistry specifications provides assurance that the program will remain effective for managing aging effects of components.

Conclusion

The Water Chemistry Control – Closed Cooling Water Program has been effective at managing aging effects. The Water Chemistry Control – Closed Cooling Water Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.41 WATER CHEMISTRY CONTROL – PRIMARY AND SECONDARY

Program Description

The Water Chemistry Control – Primary and Secondary Program is an existing program that manages aging effects caused by corrosion and cracking mechanisms. The program relies on monitoring and control of reactor water chemistry based on the EPRI guidelines in TR-105714, Rev. 5, Pressurized Water Reactor Primary Water Chemistry Guidelines, and TR-102134, Rev. 6, Pressurized Water Reactor Secondary Chemistry Guidelines.

Both the EPRI primary and secondary water chemistry guidelines make a clear distinction between "control parameters" and "diagnostic parameters." Strict adherence to control parameters is expected, whereas diagnostic parameters are suggested, but can be plant specific. Deviations from EPRI recommended diagnostic parameters are not exceptions to NUREG-1801.

NUREG-1801 states that the water chemistry control is based on guidelines in EPRI report TR-105714, Rev. 3, for primary water chemistry, and TR-102134, Rev. 3, for secondary water chemistry. IPEC has adopted TR-105714, Rev. 5, which is renumbered by EPRI to Report 1002884, and TR-102134, Rev. 6, which is renumbered by EPRI to Report 1008224.

The Revision 5 changes to TR-105714 consider the most recent operating experience and laboratory data. It reflects increased emphasis on plant-specific optimization of primary water chemistry to address individual plant circumstances and the impact of the Nuclear Energy Institute (NEI) steam generator initiative, NEI 97-06, which requires utilities to meet the intent of the EPRI guidelines. TR-105714, Rev. 5, attempts to clearly distinguish 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.

Future revisions of the EPRI primary and secondary water chemistry guidelines will be adopted as required, commensurate with industry standards.

The One-Time Inspection Program for Water Chemistry utilizes inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – Primary and Secondary Program has been effective at managing aging effects.

NUREG-1801 Consistency

The Water Chemistry Control – Primary and Secondary Program is consistent with the program described in NUREG-1801, Section XI.M2, Water Chemistry with one enhancement.

Exceptions to NUREG-1801

None

Enhancements

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

Attributes Affected	Enhancement
3. Parameters Monitored or Inspected 6. Acceptance Criteria	IP2: Revise appropriate procedures to test sulfates monthly in the RWST with a limit of < 150 ppb.

Operating Experience

A QA audit of the primary and secondary plant chemistry program was conducted in August 2003. 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). In addition, the chemistry processes were effective in implementing industry guidelines, such as EPRI and INPO guidelines, designed to extend the operating life of primary and secondary systems and components. Continuous program improvement through adoption of evolving industry guidelines provides assurance that the program will remain effective for managing the effects of aging on plant components.

Conclusion

The Water Chemistry Control – Primary and Secondary Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.2 REFERENCES

B.2-1 NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, September 2005.

B.2-2 NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*, U.S. Nuclear Regulatory Commission, September 2005.