Enclosure 3

Point Beach Nuclear Plant Units 1 and 2 Subsequent License Renewal Application (Public Version)

November 2020

Attachment 1

(1528 Total Pages, including cover sheets)

Point Beach Nuclear Plant
Units 1 and 2
Subsequent License Renewal Application
(Public Version)

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1.0 ADMINISTRATIVE INFORMATION

Pursuant to Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR 54), *Requirements for Renewal of Operating Licenses for Nuclear Power* Plants (Reference 1.6.1), this subsequent license renewal application (SLRA) seeks renewal for an additional 20-year term of the facility operating licenses for Point Beach Nuclear Plant (PBN) Unit 1 (DPR-24) (Reference 1.6.2) and Unit 2 (DPR-27) (Reference 1.6.3). The SLRA includes renewal of the source, special nuclear, and byproduct materials licenses that are combined in the Unit 1 and Unit 2 licenses.

The SLRA is based on the guidance provided by the Nuclear Regulatory Commission (NRC) in NUREG-2192, *Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants* (Reference 1.6.4), Regulatory Guide (RG) 1.188, Revision 2, *Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses* (Reference 1.6.5), and the guidance provided by Nuclear Energy Institute (NEI) 17-01, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal* (Reference 1.6.6).

The SLRA is intended to provide sufficient information for the NRC to complete its technical and environmental reviews pursuant to 10 CFR Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*, and 10 CFR Part 51, *Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions* (Reference 1.6.7). The SLRA is provided to meet the standards required by 10 CFR 54.29 in support of the issuance of the subsequent renewed operating licenses for PBN Units 1 and 2.

1.1. GENERAL INFORMATION

The following is general information required by 10 CFR 54.17 and 10 CFR 54.19.

1.1.1. Name of Applicant

NextEra Energy Point Beach, LLC (NEPB), a Wisconsin Limited Liability Company (LLC), hereby applies for subsequent renewed operating licenses for PBN Units 1 and 2. NEPB is an indirect wholly-owned subsidiary of NextEra Energy, Inc, which is based in Juno Beach, Florida. NEPB is the licensed operator and owner of PBN, Units 1 and 2.

1.1.2. Address of Applicant

NextEra Energy Point Beach, LLC
700 Universe Boulevard
Juno Beach, FL 33408-0420

Address of the Point Beach Nuclear Plant:
Point Beach Nuclear Plant Units 1 and 2
6610 Nuclear Road
Two Rivers, WI 54241

1.1.3. Descriptions of Business or Occupation of Applicant

NEPB is currently engaged principally in the business of generating electricity for sale on the wholesale market.

The current PBN Units renewed operating licenses will expire as follows:

- At midnight on October 05, 2030, for PBN Unit 1 (Renewed Facility Operating License No. DPR-24)
- At midnight on March 08, 2033, for PBN Unit 2 (Renewed Facility Operating License No. DPR-27)

NEPB will continue as the licensed operator on the subsequent renewed operating licenses.

1.1.4. Organization and Management of Applicant

NEPB is an LLC organized under the laws of the State of Wisconsin, with its principal office located in Juno Beach, Florida.

NEPB, is a direct-wholly-owned subsidiary of ESI Energy, LLC, which is a direct, wholly-owned subsidiary of NextEra Energy Resources, LLC. NextEra Energy Resources, LLC is in turn, a direct-wholly owned subsidiary of NextEra Energy Capital Holdings, Inc, which is a direct wholly-owned subsidiary of NextEra Energy, Inc. NextEra Energy, Inc. is a public utility holding company incorporated in 1984 under the laws of the state of Florida.

NEPB is not owned, controlled, or dominated by any alien, foreign corporation, or foreign government. NEPB makes this SLRA on its own behalf and is not acting as an agent or representative of any other person.

NEPB does not have a Board of Directors. The names and business addresses of NEPB's principal officers are listed below. All persons listed are U.S. citizens.

Names and Addresses of the Principal Officers		
Name	Title	Address
Crews, Terrell Kirk II	President	NextEra Energy Point Beach, LLC 700 Universe Boulevard Juno Beach, FL 33408-0420
Beilhart, Kathy A.	Vice President & Treasurer	NextEra Energy Point Beach, LLC 700 Universe Boulevard Juno Beach, FL 33408-0420
Handel, Matthew S.	Vice President	NextEra Energy Point Beach, LLC 700 Universe Boulevard Juno Beach, FL 33408-0420
McCartney, Eric	Vice President	NextEra Energy Point Beach, LLC 700 Universe Boulevard Juno Beach, FL 33408-0420
Moul, Donald A.	Executive Vice President & Chief Nuclear Officer	NextEra Energy Point Beach, LLC 700 Universe Boulevard Juno Beach, FL 33408-0420
Seal, Christine	Vice President	NextEra Energy Point Beach, LLC 700 Universe Boulevard Juno Beach, FL 33408-0420
Plotsky, Melissa A.	Secretary	NextEra Energy Point Beach, LLC 700 Universe Boulevard Juno Beach, FL 33408-0420

1.1.5. Class of License, the Use of the Facility, and the Period of Time for Which the License is Sought

NEPB requests subsequent renewal of the renewed operating licenses issued under Section 104b of the Atomic Energy Act of 1954, as amended, for PBN Unit 1 and Unit 2 (License Nos. DPR-24 and DPR-27, respectively), for a period of 20 years beyond the expiration of the current renewed operating licenses. This would extend the renewed operating license for PBN Unit 1 from midnight on October 05, 2030, to midnight October 05, 2050, and PBN Unit 2 renewed operating license from midnight on March 08, 2033, to midnight on March 08, 2053. This SLRA includes a request for renewal of those NRC source material, special nuclear material, and by-product material licenses that are subsumed into or combined with the current renewed operating licenses.

The facility will continue to be known as the PBN and will continue to generate electric power during the subsequent license renewal (SLR) period.

1.1.6. Earliest and Latest Dates for Alterations

NEPB does not propose to construct or alter any production or utilization facility in connection with this SLRA. In accordance with 10 CFR 54.21(b), during NRC review of this SLRA, an annual update to the SLRA to reflect any change to the current licensing basis (CLB) that materially affects the content of the SLRA will be provided.

1.1.7. Regulatory Agencies with Jurisdiction

Regulatory agencies with jurisdiction over the PBN revenue are:

United States Securities and Exchange Commission
100 F Street NE
Washington, D.C. 20549

Federal Energy Regulatory Commission
888 First St. NE
Washington, D.C. 20426

Public Service Commission of Wisconsin
610 N Whitney Way
PO Box 7854
Madison, WI 53707-7854

1.1.8. Local News Publications

News publications that circulate in the area surrounding the PBN and are considered appropriate to give reasonable notice of this SLRA to those municipalities, private utilities, public bodies and cooperatives that might have a potential interest in the facility, include the following:

Manitowoc Herald Times Reporter
902 Franklin Street
Manitowoc, WI 54220

Green Bay Press Gazette
435 E. Walnut St.
Green Bay, WI 54305-3430

1.1.9. Conforming Changes to Standard Indemnity Agreement

The requirements of 10 CFR 54.19(b) state that SLRAs must include, "…conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license". The current indemnity agreement No. B-41 for PBN Units 1 and 2 states, in Article VII, that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the attachment to the agreement, which is the last to expire. Item 3 of the attachment to the indemnity agreement, as revised by Amendment No. 14, lists DPR 24 and DPR 27 as the applicable license numbers. Should the license numbers be changed upon issuance of the subsequent renewed licenses, NEPB requests that conforming changes be made to Item 3 of the Attachment, and any other sections of the indemnity agreement as appropriate.

1.1.10. Restricted Data Agreement

This SLRA does not contain restricted data or other national defense information, and the applicant does not expect that any activity under the subsequent renewed operating licenses for the PBN Units will involve such information. However, pursuant to 10 CFR 54.17(f) and (g), and 10 CFR 50.37 (Reference 1.6.8), the applicant agrees that it will not permit any individual to have access to, or any facility to possess, restricted data or classified national security information until the individual and/or facility has been approved for such access under the provisions of 10 CFR 25, *Access Authorization* (Reference 1.6.9), and/or 10 CFR 95, *Facility Security Clearance and Safeguarding of National Security Information and Restricted Data* (Reference 1.6.10).

1.2. PLANT DESCRIPTION

The PBN site includes two units, Units 1 and 2. Each of the two nuclear units employs a pressurized water nuclear steam supply system (NSSS) with two coolant loops furnished by the Westinghouse Electric Corporation. Each reactor was originally designed to produce a core thermal power output of 1519 megawatts-thermal (MWt) with a corresponding gross electrical output of approximately 524 (Unit 1) and 524 (Unit 2) megawatts-electric (MWe). Commercial operation for Unit 1 began on October 05, 1970 and for Unit 2 on March 08, 1973.

Since being placed into commercial operation, each unit has undergone a low pressure turbine retrofit modification that increased the gross electric output to approximately 538 MWe. In addition, a measurement uncertainty recapture (MUR) power uprate was implemented for both units. The MUR uprate increased the license reactor core thermal power for each unit to 1540 MWt and turbine generator electric output to approximately 545 MWe.

In 2011, an Extended Power Uprate (EPU) increased the reactor thermal power to 1800 MWt for each unit, and the turbine generator electric output to approximately 640 MWe. For EPU, modifications were made to each unit's high pressure turbines, instrumentation and controls, and the associated steam, condensate, and feedwater paths.

The major structures are two containments, one auxiliary building, one pumphouse, one turbine building (including the control room), one emergency diesel generator building, and one service building. Each containment is a steel lined concrete cylinder with pre stressed tendons in the walls and dome, anchored to a reinforced concrete foundation slab which is supported by steel H piles driven to refusal in the underlying bedrock.

NEPB also operates an independent spent fuel storage installation (ISFSI) at the site. The ISFSI is operated under a general license issued pursuant to the provisions of 10 CFR 72 (Reference 1.6.11). Therefore, the ISFSI is not in-scope for subsequent license renewal.

1.3. APPLICATION STRUCTURE

This SLRA is structured in accordance with RG 1.188, Revision 2, *Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses* and NEI 17-01, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal*. The SLRA is structured to address the guidance provided in NUREG-2192, *Standard Review Plan for Review of Subsequent License Renewal Applications for* Nuclear *Power Plants*. NUREG-2192 references NUREG-2191, *Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report* (Reference 1.6.12). NUREG-2191 was used to determine the adequacy of existing aging management programs (AMPs) and to identify existing programs that will be augmented and identify new programs for SLR. The results of the aging management review (AMR), using NUREG-2191, have been documented and are illustrated in table format in Section 3, Aging Management Review Results, of this SLRA.

PBN Units 1 and 2 are constructed of similar materials with similar environments. Unless otherwise noted throughout this SLRA, plant systems and structures discussed in this SLRA apply to both units.

The SLRA is divided into the following sections and appendices:

Section 1 - Administrative Information

This section provides the administrative information required by 10 CFR 54.17 and 10 CFR 54.19. It describes the plant and states the purpose for this SLRA. Included in this section are the names, addresses, business descriptions, as well as other administrative information. This section also provides an overview of the structure of the SLRA, and a listing of acronyms and general references used throughout the SLRA.

Section 2 - Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review and Implementation Results

Section 2.1 describes and justifies the methods used in the integrated plant assessment (IPA) to identify those structures and components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(2). These methods consist of: (1) scoping, which identifies the systems, structures, and components (SSCs) that are within the scope of 10 CFR 54.4(a), and (2) screening under 10 CFR 54.21(a)(1), which identifies those in-scope SSCs that perform intended functions without moving parts or a change in configuration or properties, and that are not subject to replacement based on a qualified life or specified time period.

Additionally, the results for scoping and screening of systems and structures are described in this section. Scoping results are presented in Section 2.2, Plant Level Scoping Results. Screening results are presented in Sections 2.3, 2.4, and 2.5.

The screening results consist of lists of components or component groups and structures that require AMR. Brief descriptions of mechanical systems, electrical and instrumentation and controls (I&C), and structures within the scope of SLR are provided as background information. Mechanical systems, electrical and I&C, and structures intended functions are provided for in-scope systems and structures. For each in-scope system and structure, components requiring an AMR and their associated component intended functions are identified, and reference is made to the appropriate Section 3 table providing the AMR results.

Selected components, such as equipment supports, structural items (e.g., penetration seals, structural bolting and insulation), and passive electrical components, were more effectively scoped and screened as commodities. Under the commodity approach, these component groups were evaluated based upon common environments and materials. Commodities requiring an AMR are presented in Sections 2.4 and 2.5. Component intended functions and reference to the applicable Section 3 table are provided.

The descriptions of systems in Section 2 identify SLR boundary drawings that depict the components subject to AMR for mechanical systems. The drawings are provided in a separate submittal.

Section 3 - Aging Management Review Results

10 CFR 54.21(a)(3) requires a demonstration that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the subsequent period of extended operation (SPEO). Section 3 presents the results of the AMRs. Section 3 is the link between the scoping and screening results provided in Section 2 and the AMPs provided in Appendix B.

AMR results are presented in tabular form, in a format in accordance with NUREG-2192, *Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants*. For mechanical systems, AMR results are provided in Sections 3.1 through 3.4 for the reactor coolant system (RCS), engineered safety features (ESFs), auxiliary systems, and steam and power conversion systems, respectively. AMR results for structures and component supports are provided in Section 3.5. AMR results for electrical commodities are provided in Section 3.6.

Tables are provided in each of these sections, in accordance with NUREG-2192, to document AMR results for components, materials, environments, and aging effects that are addressed in NUREG-2191, and information regarding the degree to which the proposed AMPs are consistent with those recommended in NUREG-2191.

Section 4 - Time-Limited Aging Analyses

Time-limited aging analyses (TLAAs), as defined by 10 CFR 54.3, are listed in this section. This section includes each of the TLAAs identified in NUREG-2192 and in plant-specific analyses. This section includes a summary of the time-dependent aspects of the analyses. A demonstration is provided to show that the analyses remain valid for the SPEO, the analyses have been projected to the end of the SPEO, or that the effects of aging on the intended function(s) will be adequately managed for the SPEO, consistent with 10 CFR 54.21(c)(1)(i)-(iii). Section 4 also confirms that there are no 10 CFR 50.12 exemptions involving TLAAs as defined in 10 CFR 54.3 identified for the SPEO.

Appendix A - Updated Final Safety Analysis Report Supplement

As required by 10 CFR 54.21(d), the Updated Final Safety Analysis Report (UFSAR) supplement contains a summary of activities credited for managing the effects of aging for the SPEO. A summary description of the evaluation of TLAAs for the SPEO is also included. In addition, summary descriptions and dispositions of SLR commitments are provided. The SLR commitments are identified in Table 16-3 of Appendix A of this SLRA; the information in Appendix A is intended to fulfill the requirements of 10 CFR 54.21(d). Following issuance of the renewed licenses, the material contained in this appendix will be incorporated into the UFSAR.

Appendix B - Aging Management Programs

This appendix describes the programs and activities that are credited for managing aging effects for components or structures during the SPEO based upon the AMR results provided in Section 3 and the TLAAs results provided in Section 4.

Sections B.2.2 and B.2.3 discuss those programs that are contained in Chapter X and Chapter XI, respectively, of NUREG-2191. A description of the AMP is provided, and a conclusion based upon the results of an evaluation against each of the 10 elements provided in NUREG-2191 is drawn. In some cases, exceptions, justifications, and / or enhancements for managing aging are provided for specific NUREG-2191 elements. Additionally, operating experience (OE) related to the AMP is provided. If any plant-specific AMPs are added (now or in future RAI responses), then these AMPS will be added to these sections and evaluated against all 10 AMP elements.

Appendix C - Licensee Specific Activities Relative to the Reactor Vessel Internals

This appendix provides the gap analysis for SLR when compared to the current PBN Reactor Vessel Internals Program based on the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP)-227-A (References 1.6.13 and 1.6.14) as the starting point.

Appendix D - Technical Specification Changes

This appendix satisfies the requirement in 10 CFR 54.22 to identify technical specification changes or additions necessary to manage the effects of aging during the SPEO. There are no technical specification changes identified necessary to manage the effects of aging during the SPEO.

Appendix E - Environmental Information – Point Beach Nuclear Plant Units 1 and 2

This appendix satisfies the requirements of 10 CFR 54.23 to provide a supplement to the environmental report (ER) that complies with the requirements of subpart A of 10 CFR 51 for PBN Plant Units 1 and 2.

1.4. CURRENT LICENSING BASIS CHANGES DURING NRC REVIEW

In accordance with 10 CFR 54.21(b), during NRC review of this SLRA, an annual update to the SLRA to reflect any change to the CLB that materially affects the content of the SLRA will be provided.

In accordance with 10 CFR 54.21(d), PBN will maintain (1) a summary description of programs and activities in the UFSAR for managing the effects of aging and (2) summaries of the TLAA evaluations and (3) descriptions of the license renewal commitments for the SPEO.

1.5. CONTACT INFORMATION

Any notices, questions, or correspondence in connection with this filing should be directed to:

William D. Maher
Senior Director, Licensing
NextEra Energy Point Beach, LLC
700 Universe Boulevard
Juno Beach, FL 33408-0420

E-mail: William.Maher@fpl.com

1.6. GENERAL REFERENCES

1.6.1 10 CFR 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants.

1.6.2 DPR-24, PBN Facility Operating License for Point Beach Nuclear Plant Unit 1, ADAMS Accession No. ML053110031, December 22, 2005.

1.6.3 DPR-27, PBN Facility Operating License for Point Beach Nuclear Plant Unit 2, ADAMS Accession No. ML053110034, December 22, 2005.

1.6.4 NUREG-2192, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants, United States Nuclear Regulatory Commission, July 2017, ADAMS Accession No. ML16274A402.

1.6.5 Regulatory Guide 1.188, Revision 2, Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses, ADAMS Accession No. ML20017A265.

1.6.6 NEI 17-01, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal Rule, December 2017, ADAMS Accession No. ML17339A599.

1.6.7 10 CFR 51, Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions.

1.6.8 10 CFR 50, Domestic Licensing of Production and Utilization Facilities.

1.6.9 10 CFR 25, Access Authorization.

1.6.10 10 CFR 95, Facility Security Clearance and Safeguarding of National Security Information and Restricted Data.

1.6.11 10 CFR 72, “Licensing Requirements for the Independent Storage of Spent Nuclear Fuel, High-Level Radioactive Waste, and Reactor-Related Greater Than Class C Waste”.

1.6.12 NUREG-2191, Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report, Volumes 1 and 2, United States Nuclear Regulatory Commission, July 2017, ADAMS Accession Nos. ML16274A389 and ML16274A399.

1.6.13 EPRI Materials Reliability Program (MRP) Report 1016596, Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-Rev. 0), Revision 0, December 2008, ADAMS Accession No. ML12275A507.

1.6.14 EPRI MRP Report 1022863, Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A-Rev. 0), Revision 0, December 2011, ADAMS Accession No. ML13322A454.

1.6.15 "Application for Renewed Operating Licenses Point Beach Nuclear Plant Units 1 & 2", December 22, 2005, Submittal Letter ADAMS Accession No. ML040580023.

1.6.16 NEI 95-10, Revision 6, "Industry Guidelines for Implementing the Requirements of 10 CFR 54 – The License Renewal Rule," June 2005, ADAMS Accession No. ML051860406.

1.6.17 10 CFR 50.48, Fire Protection.

1.6.18 10 CFR 50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants.

1.6.19 10 CFR 50.61, Fracture Toughness Requirements for Protection against Pressurized Thermal Shock Events.

1.6.20 10 CFR 50.62, Requirements for Reduction of Risk from Anticipated Transients without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants.

1.6.21 10 CFR 50.63, Loss of All Alternating Current Power.

1.6.22 NFPA 805, Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001.

1.6.23 NUREG-1839, Safety Evaluation Report Related to the License Renewal of Point Beach Nuclear Plant, Units 1 and 2, December 2005.

1.6.24 NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants: Resolution of Generic Technical Activity A-36, July 1980.

1.6.25 Regulatory Guide 1.190, Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, Revision 0, March 2001.

1.6.26 NUREG-0933, Resolution of Generic Safety Issues, U.S. Nuclear Regulatory Commission, Supplement 34, December 2011.

1.6.27 NUREG-1509, Radiation Effects on Reactor Pressure Vessel Supports, R. E. Johnson, R. E. Lipinski, May 1996.

1.6.28 Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," May 1988.

1.6.29 NRC Bulletin 88-08, Supplements 1 through 3, "Thermal Stresses in Piping Connected to Reactor Coolant Systems", April 11, 1989.

1.6.30 ASME Section III, Rules for Construction of Nuclear Vessels, 1965 Edition through Summer 1966 Addenda.

1.6.31 NUREG/CR-6909, Revision 1, "Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, Final Report", May 2018.

1.6.32 NUREG/CR-5640 (SAIC-89/1541), “Overview and Comparison of U.S. Commercial Nuclear Power Plants”, September 1990.

1.6.33 NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment,” U. S. Nuclear Regulatory Commission, July 1981.

1.6.34 Regulatory Guide 1.89, Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants, Revision 1, June 1984.

1.6.35 Regulatory Guide 1.35, “Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments,” Office of Nuclear Regulatory Research, U.S. Nuclear Regulatory Commission, Revision 3, July 1990.

1.6.36 Regulatory Guide 1.35.1, Determining Prestressing Forces for Inspection of Prestressed Concrete Containments, July 1990.

1.6.37 American Society of Mechanical Engineers (ASME), Boiler and Pressure Vessel Code, Section XI, 2001 Edition through the 2003 Addenda, Subsection IWL, “Requirements for Class CC Concrete Components of Light-Water Cooled Plants”.

1.6.38 NUREG/CR-4513, Revision 2, “Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems,” May 2016.

1.6.39 NUREG-0800, Standard Review Plan, Revision 1, Section 3.6.3, “Leak-Before-Break Evaluation Procedures,” March 2007.

1.6.40 NUREG-1801, Generic Aging Lessons Learned (GALL) Report, U.S. Nuclear Regulatory Commission, July 2001.

1.6.41 NUREG/CR-4513 ANL-93/22, Revision 1, “Estimation Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems,” August 1994.

1.6.42 ASME Boiler and Pressure Vessel Code, Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” 2007 Edition with 2008 Addendum.

1.6.43 ASME Boiler & Pressure Vessel Code Section XI, Code Case N-481, “Alternative Examination Requirements for Cast Austenitic Pump Casings,” Approval Date: March 5, 1990.

1.6.44 ANSI Standard B30.2-1976, “Overhead and Gantry Cranes”.

1.6.45 10 CFR 50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.

1.6.46 10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.

1.6.47 NUREG-0737, Clarification of TMI Action Plan Requirements, ADAMS Accession No. ML051400209, November 1980.

1.6.48 NEI 14-12, Aging Management Program Effectiveness, Revision 0, December 2014, ADAMS Accession No. ML15090A665.

1.6.49 NEI 14-13, Use of Industry Operating Experience for Age-Related Degradation and Aging Management Programs, Revision 1, June 2015.

1.6.50 EPRI 3002000505, Pressurized Water Reactor Primary Water Chemistry Guidelines: Revision 7, Volumes 1 and 2, April 2014.

1.6.51 EPRI 3002010645, Pressurized Water Reactor Secondary Water Chemistry Guidelines: Revision 8, September 2017.

1.6.52 Regulatory Guide 1.65, Materials and Inspections for Reactor Vessel Closure Studs, Revision 1, April 2010.

1.6.53 NEI 03-08, Guideline for the Management of Material Issues, Revision 2, January 2010, ADAMS Accession No. ML082590651.

1.6.54 EPRI MRP Report 3002010399, MRP-228, Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals – 2018 Update, Revision 3, November 2018, ADAMS Accession No. ML19081A058.

1.6.55 EPRI 3002000563, Recommendations for an Effective Flow-Accelerated Corrosion Program (NSAC-202L-R4), November 2013.

1.6.56 NUREG-1339, Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants, ADAMS Accession No. ML031430208, June 1990.

1.6.57 EPRI NP-5769, Degradation and Failure of Bolting in Nuclear Power Plants, Volume 1, April 1988.

1.6.58 EPRI 1015336, Nuclear Maintenance Applications Center: Bolted Joint Fundamentals, December 2007.

1.6.59 EPRI 1015337, Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints, December 2007.

1.6.60 EPRI 3002007572, Steam Generator Management Program: Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 8, June 2016.

1.6.61 EPRI 1022832, Steam Generator Management Program: PWR Primary-to-Secondary Leak Guidelines, Revision 4, November 2011.

1.6.62 EPRI 3002007571, Steam Generator Management Program: Steam Generator Integrity Assessment Guidelines: Revision 4, June 2016.

1.6.63 EPRI 3002007856, Steam Generator Management Program: Steam Generator In Situ Pressure Test Guidelines, Revision 5, November 2016.

1.6.64 EPRI 3002002850, Steam Generator Management Program: Investigation of Crack Initiation and Propagation in the Steam Generator Channel Head Assembly, October 2014.

1.6.65 EPRI 3002000590, Closed Cooling Water Chemistry Guideline: Revision 2, December 2013.

1.6.66 NFPA 25, Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems, 2011 Edition.

1.6.67 EPRI 1007933, Aging Assessment Field Guide, December 2003.

1.6.68 WCAP-12866, “Bottom Mounted Instrumentation Flux Thimble Wear (PROPRIETARY)”.

1.6.69 Regulatory Guide 1.54, Service Level I, II, III, and In-Scope License Renewal Protective Coatings Applied to Nuclear Power Plants, Revision 3, April 2017.

1.6.70 Regulatory Guide 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 4, August 2018.

1.7. ACRONYMS

Table 1.7
Acronyms

Acronym	Description
AC	Alternating Current
AAC	Alternate AC
ACC	Automated Cycle Counting
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	Aluminum Conductor Steel Reinforced
ADAMS	Agencywide Documents Access and Management System
AFW	Auxiliary Feedwater
ALE	Adverse Localized Environment
AMP	Aging Management Program
AMR	Aging Management Review
AMSAC	ATWS Mitigating System Actuating Circuitry
ANSI	American National Standards Institute
AOP	Abnormal Operating Procedure
AOR	Analysis of Record
AOV	Air Operated Valve
AR	Action Request or Aspect Ratio
ART	Adjusted Reference Temperature
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASR	Alkali-Silica Reaction
AST	Alternate Source Team

Table 1.7
Acronyms

Acronym	Description
ASTM	American Society for Testing and Materials
ATWS	Anticipated Transients Without Scram
AVB	Anti-Vibration Bars
AWS	American Welding Society
A600TT	Thermally Treated Alloy 600
A690TT	Thermally Treated Alloy 690
BBRV	Birkenmaier, Brandestini, Ross, and Voight
B&PV	Boiler and Pressure Vessel
BMI	Bottom Mounted Instrument
BS	Boron Recycle
BSW	Biological Shield Wall
BTP	Branch Technical Position
B&W	Babcock and Wilcox
B&WOG	Babcock and Wilcox Owners Group
BWR	Boiling Water Reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Project
C (°C)	Degrees Celsius
CAP	Corrective Action Program
CASS	Cast Austenitic Stainless Steel
CB	Control Building
CBF	Cycle-Based Fatigue
CBSE	Common Basis Stress Evaluation
CC	Component Cooling Water System

Table 1.7
Acronyms

Acronym	**Description**
CCW	Component Cooling Water
CCCW	Closed-Cycle Cooling Water
CDF	Core Damage Frequency
CE	Combustion Engineering
CET	Core Exit Thermocouple
CETNA	Core Exit Thermocouple Nozzle Assembly
CF	Chemistry Factors
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CI	Confirmatory item
CLB	Current Licensing Basis
CMAA	Crane Manufacturers Association of America
CMTR	Certified Material Test Report
CPP	Pipe Containment Penetrations
CPVC	Chlorinated Poly-Vinyl Chloride
CR	Condition Report
CRD	Control Rod Drive
CRDM	Control Rod Drive Mechanism
CRGT	Control Rod Guide Tube
CRUD	Chalk River Unidentified Deposits
CS	Carbon Steel
CST	Condensate Storage Tank
CSUP	Component Support

Table 1.7
Acronyms

Acronym	**Description**
CUF	Cumulative Usage Factor
CUF_{en}	Cumulative Usage Environmental Factor
CWPH	Circulating Water Pumphouse
CV	Chemical and Volume Control
CW	Circulating Water System
CWPH	Circulating Water Pumphouse
DA	Degradation Assessment
DBA	Design Basis Accident or Design Basis Assurance
DBAI	Design Basis Assurance Inspection
DBD	Design Basis Document
DBE	Design Basis Event
DC	Direct Current
DG	Diesel Generator
DGB	Diesel Generator Building
DI	Demineralized Water
DM	Dissimilar Metal
DMW	Dissimilar Metal Welds
DO	Dissolved Oxygen
DOR	Division of Operating Reactors
dpa	Displacements per Iron Atom
DSI	Distorted Support Indication
EAF	Environmentally Assisted Fatigue
EBA	Emergency Breathing Air

Table 1.7
Acronyms

Acronym	**Description**
EC	Engineering Change
ECCS	Emergency Core Cooling System
ECP	Electrochemical Potential
ECT	Eddy Current Testing
EDG	Emergency Diesel Generator
EFPY	Effective Full Power Years
EMA	Equivalent Margins Analysis
EPRI	Electric Power Research Institute
EPRI-MRP	Electric Power Research Institute Materials Reliability Program
EPU	Extended Power Uprate
EQ	Environmental Qualification or Environmentally Qualified
EQCK	Equipment Qualification Checklist
ER	Environmental Report
ESE	Erosion Susceptibility Evaluation
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Features Actuation System
ETSS	Eddy Current Technique Specification Sheet
F (°F)	Degrees Fahrenheit
FAC	Flow-Accelerated Corrosion
FCG	Fatigue Crack Growth
FDB	Flow Distributing Baffle
F_{en}	Environmental Fatigue Correction Factor

Table 1.7
Acronyms

Acronym	Description
FERC	Federal Energy Regulatory Commission
FF	Fluence Factor
FIN	Fix-It-Now
FME	Foreign Material Exclusion
FOCHEM	Fuel Oil Chemistry
FOPH	Fuel Oil Pumphouse
FOST	Fuel Oil Storage Tank
FP	Fire Protection
FPRA	Fire Probabilistic Risk Analysis
FSAR	Final Safety Analysis Report
FSRF	Fatigue Strength Reduction Factor
ft-lb	Foot-Pound
GALL	Generic Aging Lessons Learned
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GL	Generic Letter
GSI	Generic Safety Issue
GT	Gas Turbine
GTB	Gas Turbine Building
H*	Alternate Repair Criteria
HA	Hydrazine Addition
HAZ	Heat Affected Zone
HELB	High Energy Line Break

Table 1.7
Acronyms

Acronym	Description
HEPA	High Efficiency Particulate Absorber
HTGR	High Temperature Gas Reactor
HVAC	Heating, Ventilation, and Air Conditioning
HX	Heat Exchanger
I&C	Instrumentation and Controls
IA	Instrument Air
IASCC	Irradiation Assisted Stress Corrosion Cracking
IE	Irradiation Embrittlement
IEB	Inspection and Enforcement Bulletin
IEEE	Institute of Electrical and Electronics Engineers
IER	INPO Event Report
IGSCC	Intergranular Stress Corrosion Cracking
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IP	Inspection Procedure
IPA	Integrated Plant Assessment
IPHA	Instrument Port Head Adaptor
IR	Interaction Ratio or Insulation Resistance
ISG	Interim Staff Guidance
ISI	In-service Inspection
K	Unintentional Curvature
ksi	Kilo-pounds per Square Inch
kV	Kilovolts

Table 1.7
Acronyms

Acronym	Description
kW	Kilowatts
LAS	Low-Alloy Steel
LBB	Leak Before Break
LCC	Leak Chase Channel
LER	Licensee Event Report
LFET	Low-Frequency Electromagnetic Testing
LLC	Limited Liability Company
LLRT	Local Leak Rate Test
LO	Lubricating Oil
LOCA	Loss of Coolant Accident
LOFWTT	Loss of Feedwater Turbine Trip
LPRM	Local Power Range Monitor
LR	License Renewal
LRA	License Renewal Application
LRPM	Leakage Reduction and Preventive Maintenance
LTOP	Low Temperature Overpressure Protection
L-V	Low-Voltage
LWR	Light Water Reactor
MDAFW	Motor-driven Auxiliary Feedwater
MEB	Metal Enclosed Bus
MeV	Million Electron Volts
MFIV	Main Feedwater Isolation Valve
MFRV	Main Feedwater Relief Valve

Table 1.7
Acronyms

Acronym	Description
MIC	Microbiologically-Influenced Corrosion
MIRVP	Master Integrated Reactor Vessel Program
MPa	Megapascal
MRC	Maintenance Rule Committee
MPV	Mid Power Value
MRP	Material Reliability Program
MRV	Minimum Required Value
MSIV	Main Steam Isolation Valve
MSLB	Main Steam Line Break
MSRV	Main Steam Relief Valve
MSR	Moisture Separator Reheater
MWe	Megawatts Electric
MWt	Megawatts Thermal
MUR	Measurement Uncertainty Recapture
M-V	Medium-Voltage
NACE	National Association of Corrosion Engineers
NAMS	Nuclear Asset Management Suite
NaOH	Sodium Hydroxide
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NDF	No Degradation Found
NDTT	Nil Ductility Transition Temperature
NEE	NextEra Energy

Table 1.7
Acronyms

Acronym	Description
NEI	Nuclear Energy Institute
NEPB	NextEra Energy Point Beach, LLC
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
Ni-Cr-Fe	Nickel-Chromium-Iron Alloy
NMC	Nuclear Management Company
NSR	Nonsafety-related
NO3	Nitrate
NOS	Nuclear Oversight – Nuclear Assurance
NPO	Non-power Operations
NPS	Nominal Pipe Size
NRC	U. S. Nuclear Regulatory Commission
NSCA	Nuclear Safety Capability Assessment
NSSS	Nuclear Steam Supply System
NUGEQ	Nuclear Utility Group on Equipment Qualification
NUREG	Nuclear Regulatory Commission Regulation
OAR	Owner's Activity Report
OBD	Operable, but Degraded
ODCM	Offsite Dose Calculation Manual
ODSCC	Outer Diameter Stress Corrosion Cracking
OE	Operating Experience
OEM	Original Equipment Manufacturer
OES	Optical Emission Spectroscopy

Table 1.7
Acronyms

Acronym	Description
OLAMST	Outdoor and Large Atmospheric Metallic Storage Tank
PAA	Poly Acrylic Acid
PACV	Post-accident Containment Ventilation
PAB	Primary Auxiliary Building
PBAPS	Peach Bottom Atomic Power Station
PBN	Point Beach Nuclear Plant
P&ID	Piping and Instrument Diagram
P-T	Pressure – Temperature
PEO	Period of Extended Operation
PH	Precipitation-Hardened
PORV	Power Operated Relief Valve
PMRQ	Preventative Maintenance Requirement
PRA	Probabilistic Risk Analysis
PRT	Pressurizer Relief Tank
PSPM	Periodic Surveillance and Preventative Maintenance Program
PSW	Primary Shield Wall
PTS	Pressurized Thermal Shock
PVC	Polyvinyl Chloride
PW	Potable Water
PWM	Primary Water Makeup
PWR	Pressurized Water Reactor
PWROG	Pressurized Water Reactor Owners Group

Table 1.7
Acronyms

Acronym	**Description**
PWSCC	Primary Water Stress Corrosion Cracking
QA	Quality Assurance
QATR	Quality Assurance Topical Report
Q1	First Quarter
RAI	Request for Additional Information
RCL	Reactor Coolant Loop
RCP	Reactor Coolant Pressure
RCPB	Reactor Coolant Pressure Boundary
RCP	Reactor Coolant Pump
RCS or RC	Reactor Coolant System
RFO	Refueling Outage
RG	Regulatory Guide
RH or RHR	Residual Heat Removal System
RIVE	Radiation Induced Volumetric Expansion
RMW	Reactor Makeup Water
RMWT	Reactor Makeup Water Tank
RPV	Reactor Pressure Vessel
RT_{NDT}	Reference Temperature – NIL Ductility Transition
RT_{PTS}	Reference Temperature – Pressurized Thermal Shock
RV	Reactor Vessel
RVCH	Reactor Vessel Closure Head
RVI	Reactor Vessel Internals
RWST	Refueling Water Storage Tank

Table 1.7
Acronyms

Acronym	Description
SA	Service Air
SBO	Station Black-out
SBF	Stress-Based Fatigue
SC	Structures and Structural Components
SCC	Stress Corrosion Cracking
SE	Safety Evaluation
SEI	Structural Engineering Institute
SER	Safety Evaluation Report
SF	Spent Fuel Cooling System
SFP	Spent Fuel Pool
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SI	Safety Injection System
SIA	Structural Integrity Associates, Inc.
SLR	Subsequent License Renewal
SLRA	Subsequent License Renewal Application
SLRBD	Subsequent License Renewal Boundary Drawing
SO_2	Sulfur Dioxide
SPEO	Subsequent Period of Extended Operation
SPS	Surry Power Station
SR	Safety-Related
SRP	Standard Review Plan
SS	Stainless Steel

Table 1.7
Acronyms

Acronym	**Description**
SSA	Safe Shutdown Analysis
SSC	Systems, Structures, and Components
SSG	Standby Steam Generator
STP	Sewage Treatment Plant or South Texas Project
SW	Service Water
TB	Turbine Building
TDAFW	Turbine-driven Auxiliary Feedwater
TID	Total Integrated Dose
TMI	Three Mile Island
TLAA	Time-Limited Aging Analysis
TR	Technical Report
TRM	Technical Requirements Manual
TS	Technical Specification
TSP	Tube Support Plate
UT	Ultrasonic Testing
UFSAR	Updated Final Safety Analysis Report
USE	Upper Shelf Energy
U1	Unit 1
U2	Unit 2
V	Velocity
VNAFW	Auxiliary Feedwater Area Ventilation System
VNBI	PAB Battery and Inverter Room Ventilation System
VNBR	Battery Room Ventilation System

Table 1.7
Acronyms

Acronym	Description
VNCC	Containment Cooling System
VNCF	Containment Cleanup System
VNCOMP	Computer Room Ventilation System
VNCR	Control Room Ventilation System
VNCRD	Control Rod Drive Cooling System
VNCSR	Cable Spreading Room Ventilation System
VNDG	Diesel Generator Building Ventilation System
VNDRM	Drumming Area Ventilation System
VNGT	Gas Turbine Building Ventilation System
VNPAB	Primary Auxiliary Building Ventilation System
VNPH	Circulating Water Pump House Ventilation System
VNPSE	Containment Purge Supply and Exhaust System
VNRAD	Radwaste Ventilation System
VNRC	Reactor Cavity System
VNRF	Refueling Cavity System
VS	Void Swelling
W	Weight
WAC	Wisconsin Administrative Code
WCAP	Westinghouse Commercial Atomic Power
WD	Waste Disposal System
WEC	Westinghouse Energy Corporation
WO	Work Order
WOG	Westinghouse Owners Group

Table 1.7
Acronyms

Acronym	Description
WT	Water Treatment
W 2-loop	Westinghouse 2-loop
μ	Intentional Curvature

2.0 SCOPING AND SCREENING METHODOLOGY FOR IDENTIFYING STRUCTURES AND COMPONENTS SUBJECT TO AMR AND IMPLEMENTATION RESULTS

This section describes the process for identifying structures and components subject to AMR in the PBN integrated plant assessment (IPA). For the systems, structures, and components (SSCs) within the scope of subsequent license renewal, 10 CFR 54.21(a)(1) requires the subsequent license renewal applicant to identify and list those structures and components subject to AMR. Furthermore, 10 CFR 54.21(a)(2) requires that the methods used to implement the requirements of 10 CFR 54.21(a)(1) be described and justified. Section 2.0 of this application satisfies these requirements.

The scoping and screening portion of the integrated plant assessment process is performed in two steps. Scoping refers to the process of identifying the plant systems and structures that are to be included within the scope of subsequent license renewal in accordance with 10 CFR 54.4. The intended functions that are the bases for including the systems and structures within the scope of subsequent license renewal are also identified during the scoping process. Screening refers to the process of determining which components associated with the in-scope systems and structures are subject to aging management review in accordance with 10 CFR 54.21(a)(1) requirements. A detailed description of the PBN scoping and screening process is provided in Section 2.1.

The scoping and screening methodology is implemented in accordance with NEI 17-01, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 (Reference 1.6.6) for Subsequent License Renewal. The plant level scoping results identify the systems and structures within the scope of subsequent license renewal in Section 2.2. The screening results identify components subject to aging management review in the following SLRA sections:

- Section 2.3 for mechanical systems
- Section 2.4 for structures
- Section 2.5 for electrical and instrumentation and control (I&C) systems

2.1. SCOPING AND SCREENING METHODOLOGY

2.1.1. Introduction

This introduction provides an overview of the scoping and screening process used for the PBN Units 1 and 2 SLR project. 10 CFR 54.21 requires that each subsequent license renewal application (SLRA) contain an Integrated Plant Assessment (IPA). The content of the IPA, based on the specific criteria in 10 CFR 54.21(a), generally consists of the following:

1. Identifying the systems, structures, and components (SSCs) in the scope of the rule;
2. Identifying the structures and components subject to aging management review;
3. Assuring that the effects of aging are adequately managed.

The IPA methodology consists of three distinct processes; scoping, screening, and aging management reviews. The IPA process developed for the original PBN license renewal (LR) project is described in Section 2 of the PBN original license renewal application (Reference 1.6.15). The technical documentation developed in support of that application was used as a starting point for the development of the IPA scoping and screening process for SLR.

The initial step in the scoping process was to define the entire plant in terms of systems and structures. The systems and structures were then individually evaluated against the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3) to determine if the systems or structures perform or support a safety-related function, if failure of the systems or structures prevent performance of a safety-related function, or if the systems or structures perform functions that are integral to one of the five license renewal regulated events. The intended function(s) that are the bases for including systems and structures within the scope of SLR were also identified.

If any portion of a mechanical system met the scoping criteria of 10 CFR 54.4, it was included within the scope of SLR. The mechanical systems in the scope of SLR were then further evaluated to determine the system components that support the identified system intended function(s). The individual mechanical screening and AMR reports provide the details on the boundaries of in-scope mechanical systems.

If any portion of a structure met the scoping criteria of 10 CFR 54.4, the structure was included within the scope of SLR. Structures in the scope of SLR were then further evaluated to determine those structural components that are required to perform or support the identified structure intended function(s). The portions of each structure that are required to support the SLR intended function(s) are identified in the individual civil structural screening and AMR reports.

Electrical and instrumentation and control (I&C) systems were scoped using the same methodology as mechanical systems and structures per the scoping criteria in 10 CFR 54.4 (a)(1), (a)(2), and (a)(3). Electrical and I&C components that are part of in-scope electrical and I&C systems and in-scope mechanical systems were included within the scope of SLR.

After completion of the scoping and boundary evaluations, the screening process was performed to evaluate the structures and components within the scope of SLR to identify the long-lived and passive structures and components subject to an AMR. The passive intended functions of structures and components subject to AMR were also identified. Additional details on the screening process are provided in Section 2.1.5.

Selected components, such as equipment supports, structural items, and passive electrical components, were scoped and screened as commodities. The structural commodities were evaluated for each in-scope structure and electrical commodities were evaluated collectively.

2.1.2. Information Sources Used for Scoping and Screening

In addition to the PBN Updated Final Safety Analysis Report (UFSAR), Technical Specifications, and Technical Requirements Manual (TRM), the following additional CLB and other information sources were relied upon to a great extent in performing scoping and screening for PBN. A brief discussion of these sources is provided.

2.1.2.1. Design Basis Documents

The PBN Design Basis Documents (DBDs) were prepared for a number of support and accident mitigation systems, selected licensing issues, and UFSAR Chapter 14 Accident Analyses. The DBDs are a tool to explain the requirements behind the plant design rather than describing the design itself. DBDs are not CLB documents. DBDs are intended to complement information obtained from other sources and to identify potential reference documents.

2.1.2.2. Controlled Plant Component Database

Specific component information for structures, systems, and components at PBN can be found in the controlled component database. The plant component database is called the Nuclear Asset Management Suite (NAMS). NAMS contains as-built information on a component level and consists of multiple data fields for each component, such as design-related information, safety and seismic classifications, safety classification bases, and component tag, type, and description. Information used in this application is current with NAMS as of December 31, 2019.

2.1.2.3. Plant Drawings

PBN plant drawings were used as references when performing system, structure, and component (SSC) evaluations for SLR. These drawings and related engineering documents were utilized to determine SSC functional requirements, safety classifications, environments, materials of construction, etc., in support of scoping, screening and aging management review evaluations.

For PBN mechanical systems, all applicable piping and instrumentation diagrams (P&IDs) were reviewed to identify the specific system boundaries included in the scope of SLR. These boundaries are also depicted on the SLR boundary drawings (SLRBDs). The in-scope boundaries of the mechanical systems are highlighted in color (magenta) on each SLRBD.

2.1.2.4. Fire Protection Nuclear Safety Capability Assessment

The PBN NFPA 805 Nuclear Safety Capability Assessment was used in determining equipment required for support of the fire protection program. Specifically, this document was used to identify credited fire protection equipment that is not classified as safety-related and/or already included within the scope of SLR.

2.1.2.5. Station Blackout Equipment List

Equipment relied upon to mitigate an SBO event at PBN is described in Appendix A.1 of the UFSAR. Appendix A.1 was used to identify components and equipment credited for SBO that were not classified as safety-related and/or not already included within the scope of SLR. In accordance with Section 2.5.2.1.1 of NUREG-2192, the portion of the offsite power system that is used to connect the plant to the offsite power source is also included in the SBO scope of SLR.

2.1.2.6. Environmental Qualification Documentation

The PBN Environmental Qualification (EQ) Master List provides a detailed listing of all equipment and components that must be environmentally qualified for use in a harsh environment. The PBN EQ Master List was used to identify equipment that must meet specific environmental qualifications regardless of safety classification.

2.1.2.7. Original License Renewal Documents

Documentation from the original license renewal application (LRA) for PBN was used as a starting point for the identification of systems and structures within the scope of SLR. This documentation includes the original LRA scoping, screening, and AMR reports. The original LRA reports were reviewed and approved and are still considered Quality Assurance (QA) records.

2.1.2.8. Other Current Licensing Basis References

Other CLB references utilized in the scoping and screening process include:

- Application for Renewed Operating Licenses, PBN Units 1 and 2 and related docketed regulatory correspondence.
- NUREG-1839, Safety Evaluation Report Related to the License Renewal of the PBN, Units 1 and 2.
- NRC Safety Evaluation Reports including NRC staff review of PBN licensing submittals. Some of these documents may contain licensee commitments.
- Licensing correspondence including relief requests, Licensee Event Reports, and responses to NRC communications such as NRC bulletins, generic letters, or enforcement actions.
- Engineering evaluations, calculations, and design change package which can provide additional information about the requirements of characteristics associated with the evaluated systems, structures, or components.

2.1.3. Technical Reports

Technical reports were prepared in support of the SLRA. Engineers experienced in nuclear plant systems, programs, and operations prepared, reviewed, and approved the technical reports. The technical reports contain evaluations and bases for decisions or positions associated with SLR requirements as described below. Technical reports are prepared, reviewed, and approved in accordance with controlled project instructions, and are based on CLB source documents described in Section 2.1.2. All of this work was performed under an NRC-approved Appendix B quality assurance program.

2.1.3.1. Subsequent License Renewal Systems and Structures List

Criteria for determining which SSCs should be reviewed and evaluated for inclusion in the scope of SLR is provided in 10 CFR 54.4. The scoping process to identify systems, structures, and components that satisfy the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) is performed on systems and structures using documents that form the CLB and other information sources. The CLB for PBN Units 1 and 2 has been defined in accordance with the definition provided in 10 CFR 54.3. The key information sources that form the CLB include the UFSAR, Technical Specifications, and the docketed licensing correspondence. Other important information sources used for scoping are further described in Section 2.1.4.

The aspects of the scoping process used to identify systems and structures that satisfy the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) are described in Sections 2.1.3.2, 2.1.3.3, and 2.1.3.4, respectively. The initial step in scoping is defining the entire plant in terms of major systems and structures. As no single document source exists for PBN, this scoping technical report was prepared to establish a comprehensive list of SLR systems and structures and to document the basis for the list.

The grouping of the PBN SLR systems and structures is based on the guidance provided in NEI 17-01. The complete list of systems and structures evaluated in the scoping technical report are provided in Table 2.2-1.

Certain structures and equipment were excluded at the outset because they are not considered to be SSCs that are part of the CLB and do not have design or functional requirements related to the 10 CFR 54.4 (a)(1), (a)(2), or (a)(3) scoping criteria. These include driveways and parking lots, temporary equipment, health physics equipment, portable measuring and testing equipment, tools, and motor vehicles.

This report grouped SLR systems and structures into the following categories:

- Reactor Vessel, Internals, and Reactor Coolant System
- Engineered Safety Features
- Auxiliary Systems
- Steam and Power Conversion System
- Structures
- Electrical and Instrumentation and Controls

This grouping of the PBN SLR systems and structures is based on the guidance of NUREG-2191.

2.1.3.2. Safety-Related Criteria Pursuant to 10 CFR 54.4(a)(1)

Safety-related systems and structures are included within the scope of SLR in accordance with 10 CFR 54.4(a)(1) scoping criterion. The NAMS component database identifies safety-related components in a configuration controlled data field. In accordance with PBN plant procedures, safety-related is defined as SSCs that are relied upon during or following a design basis event (DBE) to ensure:

- The integrity of the reactor coolant pressure boundary,
- The capability to shut down the reactor and maintain it in a safe shutdown condition; or
- The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures that are comparable to the guideline exposures of 10 CFR 100 or as referred to in 10 CFR 50.34 or 10 CFR 50.67, as applicable.

This definition is technically equivalent to 10 CFR 54.4(a)(1) for purposes of SLR scoping. No safety-related components have been excluded from the scope of SLR.

In April of 2011 the NRC issued license amendments supported by a Safety Evaluation (SE) (Reference ML110240054) accepting the PBN implementation of alternate source term (AST) methodology; therefore, the requirements of 10 CFR 50.67 are applicable to PBN. As described in the SE, PBN did add new components to the 10 CFR 50.49 program due to AST. These components consist of cables, motors, and motor terminations and AST source terms were used to establish the radiation environment for these EQ components.

Safety classifications of SSCs are included in NAMS and were established based on reliance on the SSCs during and following DBEs, which include design basis accidents (DBAs), anticipated operational occurrences, natural phenomena, and external events. The DBEs considered for the PBN CLB are consistent with 10 CFR 50.49(b)(1). UFSAR Chapter 14 provides the DBE accident analyses for PBN Units 1 and 2.

Natural phenomena and external events are described in Chapter 2 and Appendices A.5 and A.7 of the PBN UFSAR and in appropriate sections of the DBDs. Structures designed to withstand DBEs, natural phenomena, and external events are described in UFSAR Chapter 5 and Appendix A.5.

The steps to identify systems and structures at PBN that meet the criteria of 10 CFR 54.4(a)(1) are outlined below:

- The UFSAR, Technical Specifications, TRM, DBDs, NAMS component database, docketed licensing correspondence, and design drawings were reviewed, as applicable.
- Based on the above, license renewal intended functions relative to the criteria of 10 CFR 54.4(a)(1) were identified for each system and structure determined to be safety-related.

The scoping process to identify safety-related systems and structures for PBN is consistent with and satisfies the criteria in 10 CFR 54.4(a)(1).

2.1.3.3. Nonsafety-Related Criteria Pursuant to 10 CFR 54.4(a)(2)

10 CFR 54.4(a)(2) states that SSCs within the scope of SLR include nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of the functions identified for safety-related SSCs. The method utilized for this scoping criteria is consistent with NUREG-2192 and NEI 17-01. Note that Section 3.1.2 of NEI 17-01 references NEI 95-10, Rev. 6, Appendix F (Reference 1.6.16), for industry guidance related to 10 CFR 54.4(a)(2) scoping criteria.

Consistent with this guidance, the nonsafety-related SSCs that are within the scope of SLR for PBN fall into three categories:

- Nonsafety-related SSCs that may have the potential to prevent satisfactory accomplishment of safety functions,
- Nonsafety-related SSCs directly connected to safety-related SSCs that provide structural support for the safety-related SSCs, and
- Nonsafety-related SSCs that are not directly connected to safety-related SSCs but have the potential to affect safety-related SSCs through spatial interactions.

The first item includes nonsafety-related SSCs credited as mitigative design features or for providing system functions relied on by safety-related SSCs in the CLB. These nonsafety-related SSCs are identified by reviewing the PBN UFSAR and other CLB documents. In addition, a supporting system review was performed to identify any nonsafety-related system that supports a safety-related intended function of a system included within the scope of SLR in accordance with 10 CFR 54.4(a)(1). Any nonsafety-related systems identified during this review are included within the scope of SLR in accordance with 10 CFR 54.4(a)(2).

The remaining two items are nonsafety-related systems with the potential for physical or spatial interaction with safety-related SSCs. Scoping of these systems is the subject of NEI 95-10, Appendix F. Additional detail on the application of the 10 CFR 54.4(a)(2) scoping criterion is provided in Section 2.1.4.2.

The scoping process to identify nonsafety-related systems and structures that can affect safety-related systems and structures for PBN is consistent with and satisfies the criteria in 10 CFR 54.4(a)(2).

2.1.3.4. Other Scoping Pursuant to 10 CFR 54.4(a)(3)

10 CFR 54.4(a)(3) states that SSCs within the scope of SLR include systems and structures relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with one or more of the following regulated events:

- Fire Protection (FP) (10 CFR 50.48) (Reference 1.6.17)
- Environmental Qualification (EQ) (10 CFR 50.49) (Reference 1.6.18)
- Pressurized Thermal Shock (PTS) (10 CFR 50.61) (Reference 1.6.19)

- Anticipated Transients Without Scram (ATWS) (10 CFR 50.62) (Reference 1.6.20)
- Station Blackout (SBO) (10 CFR 50.63) (Reference 1.6.21)

The scoping process and methodology described below for each of these regulated events is consistent with and satisfies the criteria of 10 CFR 54.4(a)(3).

2.1.3.4.1. Fire Protection (10 CFR 50.48)

10 CFR 54.4(a)(3) requires that SSCs relied on in safety analysis or plant evaluations to perform a function that demonstrates compliance with the regulations for fire protection (10 CFR 50.48) be included within the scope of SLR.

The scope of systems and structures required for fire protection to comply with the requirements of 10 CFR 50.48 includes:

- Systems and structures required to demonstrate post-fire safe shutdown capabilities
- Systems and structures required for fire detection and mitigation
- Systems and structures required to meet commitments made to Appendix A of Branch Technical Position (BTP) APCSB 9.5-1

The design of the PBN Units 1 and 2 fire protection program is based upon the defense-in-depth concept. Multiple levels of protection are provided so that should a fire occur, it will not prevent safe plant shutdown, and the risk of a radioactive release to the environment is minimized. These levels of protection include fire prevention, fire detection and mitigation, and the capability to achieve and maintain safe shutdown should a fire occur. This protection is provided through commitments made to the National Fire Protection Associate (NFPA) Standard 805 (Reference 1.6.22).

Systems and structures in the scope of SLR for fire protection include those required for compliance with 10 CFR 50.48(a) and 10 CFR 50.48(c). Equipment relied on for fire protection includes SSCs credited with fire prevention, detection, and mitigation in areas containing equipment important to safe operation of the plant, as well as systems that contain plant components credited to maintain the nuclear fuel in a safe and stable condition. For PBN to be in a “Safe and Stable” condition, performance of a transition to cold shutdown is not necessary versus what was originally required under 10 CFR 50, Appendix R. This definition of a “Safe and Stable” condition is consistent with the existing analysis documented in the PBN NFPA 805 Nuclear Safety Capability Assessment. The nuclear safety capability assessment (NSCA) is the term used by NFPA 805 to represent the safe shutdown analysis (SSA) within the context of NFPA 805.

The NSCA Equipment List is included in the NFPA 805 Nuclear Safety Capability Assessment and provides the list of equipment necessary to bring the plant to a “Safe and Stable” condition as determined by the fire SSA, fire probabilistic risk analysis (FPRA), and non-power operations (NPO) fire analysis. The NSCA Equipment List also contains power generation and distribution equipment that are required for the safe operation of the listed components.

The steps to identify systems and structures relied upon for fire protection at PBN that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSAR, Technical Specifications, TRM, Fire Protection Program Design Document, NFPA 805 Nuclear Safety Capability Assessment, NSCA Equipment List, licensing correspondence, DBDs, and design drawings were reviewed, as applicable.
- Based on the above, license renewal intended functions relative to the criterion of 10 CFR 54.4(a)(3) for fire protection were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed to for fire protection for PBN is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.3.4.2. Environmental Qualification (10 CFR 50.49)

Certain safety-related electrical components are required to withstand environmental conditions that may occur during or following a DBA per 10 CFR 50.49. The criteria for determining which equipment requires EQ are identified on the PBN Environmental Qualification (EQ) Master List for 10 CFR 50.49, which states:

Electric equipment covered in 10 CFR 50.49 is characterized as follows:

(a) *Safety-related electric equipment that is relied upon to remain functional during and following design basis events to insure*

   (i) *the integrity of the reactor coolant boundary,*
   (ii) *the capability to shut down the reactor and maintain it in a safe shutdown condition, and*
   (iii) *the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the 10 CFR 100 or 50.67 guidelines. Design Basis Events are defined as conditions of normal operation, including anticipated operational occurrences, design basis accidents, external events, and natural phenomena for which the plant must be designed to ensure functions (i) through (iii) of this paragraph.*

(b) *Nonsafety-related electric equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions specified previously.*
(c) *Certain post-accident monitoring equipment (Refer to Regulatory Guide 1.97, Revision 3, “Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs During and Following an Accident”).*

The steps to identify components subject to EQ at PBN that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSAR, Technical Specifications, TRM, Environmental Qualification DBD, EQ Master List, and licensing correspondence were reviewed, as applicable.

- Based on the above, license renewal intended functions relative to the criterion of 10 CFR 54.4(a)(3) for EQ were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed to for EQ for PBN is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3). Time-limited aging analyses (TLAAs) associated with environmentally qualified electric equipment are discussed in Section 4.0.

2.1.3.4.3. Pressurized Thermal Shock (10 CFR 50.61)

Fracture toughness requirements specified in 10 CFR 50.61 state that licensees of pressurized water reactors (PWRs) evaluate the reactor vessel beltline materials against specific criteria to ensure protection from brittle fracture.

Pressurized thermal shock (PTS) is a potential pressurized water reactor (PWR) event or transient causing vessel failure due to severe overcooling (thermal shock) concurrent with, or followed by, significant pressure in the reactor vessel. The PBN CLB shows that the Unit 1 and 2 reactor vessels have been demonstrated to meet the toughness requirements of 10 CFR 50.61 through its current 60-year end-of-license period. The PBN Units 1 and 2 PTS time-limited aging analyses (TLAAs) discussed in Section 4.0 demonstrate that the fracture toughness requirements of 10 CFR 50.61 are met for the 80-year end-of-subsequent-license renewal period.

The steps to identify systems and structures relied upon for protection against PTS at PBN that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSAR, Technical Specifications, TRM, and licensing correspondence were reviewed, as applicable.
- Based on the above, the reactor vessels are the only components relied upon for protection against PTS. Analyses applicable to PTS have been reevaluated and demonstrated that the reactors vessels meet the screening criteria at the end of the subsequent period of extended operation (SPEO).

The scoping process to identify systems and structures relied upon and/or specifically committed to for PTS for PBN is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.3.4.4. Anticipated Transient without Scram (10 CFR 50.62)

Anticipated transient without scram (ATWS) is a postulated operational transient that generates an automatic scram signal, accompanied by a failure of the reactor protection system to automatically shutdown the reactor. The ATWS rule (10 CFR 50.62) requires improvements in the design and operation of light-water cooled water reactors to reduce the likelihood of failure to automatically shutdown the reactor following anticipated transients, and to mitigate the consequences of an ATWS event.

This requirement has been satisfied at PBN by the addition of the ATWS Mitigating System Actuating Circuitry (AMSAC). The AMSAC, also known as the Loss of Feedwater Turbine Trip (LOFWTT), is designed to trip the main turbine and start the motor-driven and turbine-driven auxiliary feedwater pumps on loss of main feedwater when the reactor is above 40 percent nominal power. The PBN design features related to ATWS events are described in detail in UFSAR Section 7.4.1.

The steps to identify systems and structures relied upon for ATWS at PBN that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSAR, Technical Specifications, TRM, licensing correspondence, and design drawings were reviewed, as applicable.
- Based on the above, SLR intended functions relative to the criterion of 10 CFR 54.4(a)(3) for ATWS events were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed to for anticipated transient without scram events for PBN is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.3.4.5. Station Blackout (10 CFR 50.63)

Criterion 10 CFR 54.4(a)(3) requires that all systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for station blackout (10 CFR 50.63) be included within the scope of SLR.

A station blackout (SBO) event is a complete loss of alternating current (AC) electric power to the essential and nonessential switchgear buses in a nuclear power plant (i.e., loss of the offsite electric power system concurrent with generator trip and unavailability of the onsite emergency AC power sources). SBO does not include the assumption of loss of available AC power to buses fed by (1) station batteries through inverters or (2) alternate AC sources, nor does it assume a concurrent single failure or design basis accident.

PBN is an Alternate AC (AAC) plant. Either one of four emergency diesel generators (EDGs) or the gas turbine generator (G-05) can be used as the AAC source. An EDG can be started from the control room and can power safe shutdown buses within ten minutes of the onset of an SBO event. Since this can be accomplished from the control room within ten minutes, no detailed coping assessment is required with the EDGs credited as an AAC source. However, G-05 requires more than ten minutes to start and power safe shutdown buses. G-05 is assumed to be available within one hour of an SBO. Since G-05 continues to be credited as an AAC source, a detailed coping assessment of the capability to achieve and maintain safe shutdown for the first hour following an SBO event continues to be required.

The total coping duration is the time between the onset of SBO and the restoration of off-site AC power to safe shutdown buses. This is conservatively the time for which the AAC source must be capable of carrying SBO loads assuming that the AAC is started anytime during the first hour following the onset of SBO.

NUREG-2192, Section 2.5.2.1.1 Components Within the Scope of SBO (10 CFR 50.63) specifies that the plant portion of the offsite power system that is used to connect the plant to the offsite power source meets the requirements of 10 CFR 54.4(a)(3). The SBO scoping for PBN includes the recovery path electrical distribution equipment out to the first circuit breaker with the offsite distribution system (i.e., equipment in the switchyard) consistent with the NUREG-2192 guidance. Note that this scoping and screening effort had the objective to identify the first electrical interfacing equipment in the switchyard, under the control of the plant, which could provide a connection to offsite power following an SBO event. The 345kV switchyard provides interconnections between the Unit 1 high-voltage station auxiliary transformer and the Unit 1 345kV circuit switcher as well as between the Unit 2 high-voltage station auxiliary transformer and the Unit 345kV circuit switcher. The Unit 1 and Unit 2 circuit switchers are the last components in the connection to offsite power controlled by PBN operators and demarcate the SBO switchyard boundary for SLR. Off-site power flows from the high-voltage station auxiliary transformers to the safety related busses in the 13.8kV and 4160V Power Systems.

The electrical interconnection between PBN Units 1 and 2 and the offsite transmission network and the off-site power recovery paths following an SBO are highlighted on electrical boundary drawing SLR-ELECTRICAL-E1. The PBN SBO coping and recovery path are further described in the electrical commodity screening and AMR results presented in Section 2.5.

Design features to satisfy the PBN SBO Rule are described in UFSAR Appendix A.1 and the SBO DBD.

The steps to identify systems and structures relied upon for SBO at PBN that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSAR, Technical Specifications, TRM, licensing correspondence, SBO DBD, and design drawings were reviewed, as applicable.
- Based on the above, license renewal intended functions relative to the criterion of 10 CFR 54.4(a)(3) for SBO were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed to for SBO for PBN is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.4. Scoping Methodology

The scoping process is the systematic process used to identify the PBN SSCs within the scope of SLR. The scoping process was initially performed at the system and structure level, in accordance with the scoping criteria identified in 10 CFR 54.4(a). System and structure functions and intended functions were identified from a review of the source CLB documents. The system and structure scoping results are provided in Table 2.2-1.

The PBN scoping process began with the development of a comprehensive list of plant systems and structures, as described in Section 2.1.3.1.

Each PBN system and structure was then reviewed for inclusion in the scope of SLR using the criteria of 10 CFR 54.4(a). These criteria are as follows:

- Title 10 CFR 54.4(a)(1) – Safety-related
- Title 10 CFR 54.4(a)(2) – Nonsafety-related affecting safety-related
- Title 10 CFR 54.4(a)(3) – Regulated Events:
    - Fire Protection (10 CFR 50.48)
    - EQ (10 CFR 50.49)
    - PTS (10 FR 50.61)
    - ATWS (10 CFR 50.62)
    - SBO (10 CFR 50.63)

2.1.4.1. Safety-Related – 10 CFR 54.4(a)(1)

In accordance with 10 CFR 54.4(a)(1), SSCs within the scope of license renewal include:

Safety-related systems, structures, and components which are those relied upon to remain functional during the following design-basis events (as defined in 10 CFR 50.49(b)(1), to ensure the following functions –

(i) *The integrity of the reactor coolant pressure boundary;*
(ii) *The capability to shutdown the reactor and maintain it in a safe shutdown condition; or*
(iii) *The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable*.

At PBN, the safety-related components are identified in NAMS. The safety-related classification in NAMS was populated using a controlled procedure that is consistent with the above 10 CFR 54.4(a)(1) criteria and design verified. The safety-related classification is also considered a controlled attribute in the database, and any modification to a component's safety classification must be design verified.

Safety-related classifications for systems and structures are based on system and structure descriptions and analysis in the UFSAR. Safety-related structures are those structures listed in the UFSAR and classified as Class I. Systems and structures identified as safety-related in the UFSAR meet the criteria of 10 CFR 54.4(a)(1) and are included within the scope of SLR. Safety-related components in NAMS were also reviewed, and the systems and structures that contained these components were also included within the scope of SLR. The review also confirmed that all plant conditions, including conditions of normal operation, internal events, anticipated operational occurrences, DBAs, external events, and natural phenomena as described in the CLB, were considered for SLR scoping.

2.1.4.2. Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)

In accordance with 10 CFR 54.4(a)(2), the SSCs within the scope of license renewal include:

> *All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1)(i), (ii), or (iii).*

This scoping criterion requires an assessment of nonsafety-related SSCs with respect to the following application or configuration categories:

- Nonsafety-related SSCs that may have the potential to prevent satisfactory accomplishment of safety functions,
- Nonsafety-related SSCs directly connected to safety-related SSCs that provide structural support for the safety-related SSCs, and
- Nonsafety-related SSCs that are not directly connected to safety-related SSCs but have the potential to affect safety-related SSCs through spatial interactions.

These categories are discussed in detail below.

2.1.4.2.1. Nonsafety-Related SSCs with Potential to Prevent Satisfactory Accomplishment of Safety Functions

This category addresses nonsafety-related SSCs that are required to function in support of SLR intended functions of safety-related SSCs. This functional requirement distinguishes this category from other categories where the nonsafety-related SSCs are only required to maintain adequate integrity to preclude structural failure or spatial interaction.

The identification of the PBN SSCs determined to be within the scope of 10 CFR 54.4(a)(2) for original PBN license renewal is described in the Integrated Plant Assessment methodology and Criterion 2 scoping methodology and results reports. These reports were used as a starting point for the determination of the SSCs within the scope of 10 CFR 54.4(a)(2) for PBN SLR. Additional sources of information used to determine this scope includes the original license renewal NRC Safety Evaluation Report, NUREG-1839 (Reference 1.6.23), plant design modifications implemented between January 1, 2003 and December 31, 2019, and the information sources listed in Section 2.1.2 of this report.

<u>Nonsafety-Related SSCs Credited Design Features in the CLB</u>

Nonsafety-related SSCs may have the potential to prevent satisfactory accomplishment of safety functions. For additional guidance, NEI 17-01 refers to the industry guidance documented in NEI 95-10, Appendix F. Items identified in the PBN CLB where this can occur include the following:

Cranes

Cranes are used in support of unit operations and maintenance activities and may be used to move heavy loads over safety-related equipment, spent fuel, or fuel in the core. The overhead-handling systems, from which a load drop could result in damage to any system that could prevent the accomplishment of a safety-related function, are considered to meet the criteria of 10 CFR 54.4(a)(2) and within the scope of SLR. The cranes and hoists that are within the scope of NUREG-0612 (Reference 1.6.24) are within-scope for subsequent license renewal.

High-Energy Line Break (HELB)

For PBN, the definition of high energy piping systems are systems which have a combined pressure and temperature rating which exceeds a service temperature of 200°F or greater and a design pressure above 275 psig. Piping systems 1” nominal pipe size and smaller are excluded from HELB review. Nonsafety-related whip restraints, jet impingement shields, blowout panels, etc. that are designed and installed to protect safety-related equipment from the effects of a HELB are within the scope of SLR per 10 CFR 54.4(a)(2).

Missiles

Missiles can be generated from internal events such as failure of rotating equipment or external events. Inherent nonsafety-related features that protect safety-related equipment from internal and external missiles are within the scope of SLR per 10 CFR 54.4(a)(2).

Flooding

Flooding from various sources is generally considered during design of the plant. Typically, only equipment in the lowest levels of the plant is susceptible to flooding. This assumes open stairwells and floor grating to allow floodwater to cascade to lower levels. If a room does not allow for cascading, it would need to be dispositioned on a plant-specific basis. If level instrumentation and alarms are utilized to warn the operators of flood conditions, and operator action is necessary to mitigate the flood, then these instruments and alarms are within the scope of SLR per 10 CFR 54.4(a)(2). Nonsafety-related sump pumps, piping and valves are necessary to mitigate the effects of a flood that threatens safety-related intended functions of SSCs are also within the scope of SLR per 10 CFR 54.4(a)(2). Walls, curbs, dikes, doors, etc. that provide flood barriers to safety-related SSCs are within the scope of SLR per 10 CFR 54.4(a)(2) and are typically included as part of the building structure.

Nonsafety-Related SSCs Required to Functionally Support Safety-Related SSCs

In some cases, safety-related SSCs may rely on certain nonsafety-related SSCs to perform a system function. These nonsafety-related SSCs include the following:

- The nonsafety-related reactor makeup water tank provides an emergency backup source of water to the component cooling water system surge tanks to accommodate leakage from the component cooling water loops as discussed in Section 2.3.3.1.

- The cooling loop for the spent fuel cooling system was in the scope of original license renewal as it performs a 10 CFR 54.4(a)(1) pressure boundary intended function. The interconnecting nonsafety-related spent fuel cooling purification sub-system was originally in scope for the 10 CFR 54.4(a)(2) leakage boundary (spatial) intended function. When in service, the purification sub-system becomes part of the spent fuel cooling loop pressure boundary. As a result, the purification sub-system is being included in the scope of SLR for functional support of the spent fuel cooling system pressure boundary intended function in accordance with 10 CFR 54.4(a)(2) as discussed in Section 2.3.3.3.

- Operation of the nonsafety-related reactor cavity cooling fans is required to maintain the air temperature in the reactor cavity less than the 150ºF air temperature limit considered in the evaluation of the primary shield wall as discussed in Section 2.3.3.9.

- The PBN control room ventilation system (VNCR), computer room ventilation system (VNCOMP), and cable spreading room ventilation system (VNCSR) are nonsafety-related. However, these systems maintain the control room envelope to limit unfiltered leakage and filter and remove particulate and iodine from the outside air during emergency operations to support control room occupancy as discussed in Section 2.3.3.10. Significant modifications were made to the VNCR to support implementation of the AST methodology in 2011.

- The PBN primary auxiliary building ventilation system (VNPAB) provides exhaust of post-LOCA airborne radionuclides from engineered safety feature system leakage via the VNPAB exhaust stack as discussed in Section 2.3.3.10.

These nonsafety-related systems were included within the scope of SLR in accordance with 10 CFR 54.4(a)(2).

2.1.4.2.2. Nonsafety-Related SSCs Directly Connected to Safety-Related SSCs that Provide Structural Support for the Safety-Related SSCs

Section 4 of Appendix F of NEI 95-10 states that for nonsafety-related SCs that are directly connected to SR SCs (typically piping systems), the nonsafety-related piping and supports, up to and including the first equivalent anchor beyond the safety-related/nonsafety-related interface, are within the scope of SLR per 10 CFR 54.4(a)(2).

For this purpose, the “first seismic or equivalent anchor” must be defined such that the failure in the nonsafety-related pipe run beyond the first seismic or equivalent anchor will not render the SR portion of the piping unable to perform its intended function under CLB design conditions.

The following criteria from Appendix F of NEI 95-10 apply to the identification of the first seismic or equivalent anchor at PBN:

- A seismic anchor is defined as a device or structure that ensures that forces and moments are restrained in three orthogonal directions.
- An equivalent anchor defined in the CLB can be credited for the 10 CFR 54.4(a)(2) evaluation.
- An equivalent anchor may also consist of a large piece of plant equipment or a series of supports that have been evaluated as a part of a plant-specific piping design analysis to ensure that forces and moments are restrained in three orthogonal directions.
- When an equivalent anchor point for a particular piping segment is not clearly described within the existing CLB information or original design basis, the use of a combination of restraints or supports such that the nonsafety-related piping and associated structures and components attached to safety-related piping is included in-scope up to a boundary point that encompasses at least two supports in each of three orthogonal directions.

An alternative to specifically identifying a seismic anchor or series of equivalent anchors that support the safety-related/nonsafety-related (SR/NRS) piping interface is to include enough of the NSR piping run to ensure that these anchors are included and thereby ensure the piping and anchor intended functions are maintained. The intended function of the first seismic or equivalent anchor consists of two facets:

(1) Providing structural support for the safety-related/nonsafety-related interface, and

(2) Ensuring nonsafety-related piping loads are not transferred through the safety-related/nonsafety-related interface.

The following methods (a) through (d) are used to define end points for the portion of NSR piping attached to SR piping to be included in the scope of SLR. The bounding criteria in methods (a) through (d) provide assurance that SLR scoping encompasses the NSR piping systems included in the design basis seismic analysis and is consistent with the CLB.

(a) A base-mounted component that is a rugged component and is designed not to impose loads on connecting piping. The SLR scope includes the base-mounted component as it has a support function for the safety-related piping.

(b) A flexible connection is considered a pipe stress analysis model end point when the flexible connection effectively decouples the piping system.

(c) A free end of NSR piping, such as a drainpipe that ends at an open floor drain.

(d) For NSR piping runs that are connected at both ends to SR piping, include the entire run of NSR piping.

For SLR, PBN follows the same approach accepted by the NRC for the original license renewal regarding nonsafety-related SSCs that are directly connected to SR SSCs (typically piping systems). Specifically, PBN has included all the connected nonsafety-related piping and supports, up to and including the first equivalent anchor beyond the safety/nonsafety interface, within the scope of SLR pursuant to 10 CFR 54.4(a)(2). The first equivalent anchor beyond the safety/nonsafety piping interface meets the criteria specified in Section 4 of Appendix F of NEI 95-10. Note that these piping segments are not uniquely identified on the SLRBDs. The aging effects for directly connected NSR piping are managed using the same programs that manage the SR piping. The associated NSR pipe supports are addressed in a commodity "spaces" approach, wherein all supports in the areas of concern, even those extending beyond the safety/nonsafety piping interface are included in the scope of SLR.

This approach is further described in the PBN response to NRC RAI 2.1-2 (Reference ML050400134) and Section 2.1.3.1.1 of NUREG-1839.

2.1.4.2.3. Nonsafety-Related SSCs that Have the Potential to Affect Safety-Related SSCs through Spatial Interactions

Nonsafety-related systems that are not connected to safety-related piping or components or are outside the structural support boundary for the attached safety- related piping system, and have a spatial relationship such that their failure could adversely impact the performance of a safety-related SSC intended function, must be evaluated for SLR scope in accordance with 10 CFR 54.4(a)(2) requirements. As described in NEI 95-10, Appendix F, there are two options when performing this scoping evaluation: a mitigative option and a preventive option.

To address this requirement of 10 CFR 54.4(a)(2), PBN has chosen the preventive option for SLR. The preventive option involves identifying the nonsafety-related SSCs that have a spatial relationship such that failure could adversely impact the performance of a safety-related SSC intended function and including the identified nonsafety-related SSC within the scope of SLR without consideration of plant mitigative features. The concern is that age-related degradation of nonsafety- related SSCs could lead to adverse interactions with safety-related SSCs that have not been previously considered.

During the original PBN LRA review, the NRC staff requested clarification of the PBN scoping criteria for 54.4(a)(2). In the original LRA, PBN evaluated the effects of “exposure duration” due to the failure of nonsafety-related equipment with vulnerable safety related equipment that is not protected from the effects of spray or leakage. PBN stated that long-term exposure to conditions resulting from a failed nonsafety-related SSC (such as leakage or spray) was not considered credible. The basis was that leakage/spray would be quickly identified by plant personnel via walkdowns, sump level trends, or system parameter monitoring and alarms, and once identified, appropriate corrective actions would be taken. Therefore, only nonsafety-related SSCs whose failure could result in a failure of a safety-related SSC due to a short-term exposure would be considered in-scope for 10 CFR 54.4(a)(2).

During its review, the NRC staff issued RAI 2.1-1 requesting PBN provide additional information to adequately define short-term exposure duration for low and moderate energy piping failures and how it relates to scoping and screening of 10 CFR 54.4(a)(2). In the response to RAI 2.1-1 (Reference ML050400134), PBN stated that for the purpose of license renewal, the term "exposure duration" would be removed from the LRA and a technical justification would be provided as to why the safety-related SSCs were capable of withstanding the effects of spray and leakage. During a meeting on February 15, 2005, the staff indicated and PBN agreed, that this response to RAI 2.1-1 required further clarification. In the clarification letter dated March 15, 2005 (Reference ML050840432) PBN committed to provide details of a change to the 10 CFR 54.4(a)(2) scoping methodology by the end of April 2005. This commitment was identified as confirmatory item (CI) 2.1-1.

In response to CI 2.1-1 (Reference ML051300355), PBN provided additional information regarding the scoping methodology changes. This revised methodology invokes a plant “spaces” approach that assumes a spatial interaction can occur if safety-related and nonsafety-related SSCs are located within the same space. For this process, a space is defined by the room in which the safety-related and nonsafety-related components are located. This revised methodology evaluated the effect of sprays and leaks on mechanical and electrical safety-related SSCs, with no limitation on duration of the sprays/leaks.

Based on this revised 10 CFR 54.4(a)(2) methodology, PBN re-evaluated SSCs to identify configurations where the failure of nonsafety-related SSCs could result in the loss of an intended function of the safety-related SSCs within the space and, were therefore, considered within the scope of license renewal. This re-evaluation led to the significant expansion of scope for some mechanical systems and to the addition of component groups and line items to several tables in the original LRA.

As described in Sections 1.6 and 2.1.3.1.1 of NUREG-1839, the NRC staff found the PBN response to RAI 2.1-1 acceptable and closed CI 2.1-1.

PBN has reviewed the resolution of CI 2.1-1 and determined that the same scoping methodology for 10 CFR 54.4(a)(2) would be utilized for SLR. The review concluded that this scoping methodology was in compliance with NEI 95-10, Appendix F and acceptable for SLR. In addition, each PBN mechanical system was reviewed and the determination was reached that no additional nonsafety-related mechanical systems need to be added to the scope of SLR for 10 CFR 54.4(a)(2) considerations. In addition, the six (6) specific exceptions to the 10 CFR 54.4(a)(2) methodology included in the PBN response to CI 2.1-1 have been evaluated for applicability to SLR. Detailed plant walkdowns were performed to address the applicability of these exceptions for SLR and the results are summarized below.

Exception 1

> “NSR SCs in containment were not re-evaluated. SR SCs within containment are already evaluated for post-accident environments including spray and/or steam. As such, the existing CLB has addressed the bounding environmental conditions for SR SCs within containment.”

Exception 1 remains applicable for SLR. Safety-related SCs within containment remain qualified for post-accident environments, including the potential effects of spray and/or steam from NSR SCs.

Exception 2

> "NSR components in rooms or cubicles where there are no SR components do not need to be in-scope. These rooms or cubicles have also been evaluated to ensure that SR piping does not run through them. The following cubicles or rooms have no SR equipment in them, and therefore NSR components in these cubicles or rooms are not in-scope:
>
> - Demineralizer cubicles and demineralizer valve gallery
> - Sump tank cubicle
> - Gas stripper building Unit 2 façade
> - Blowdown evaporator building
> - Drumming area 8 ft. truck bay Unit 2
> - Primary auxiliary building truck bay
> - B and C hold up tank (HUT) cubicles (A HUT addressed in Exception 5)
> - Laundry tank room"

Exception 2 remains applicable for SLR. SLR walkdowns were performed on each of the cubicles and rooms identified above and it was confirmed that there are no SR SCs in the areas. In addition, engineering modification packages were reviewed and also confirmed no SR equipment had been added to these areas since the original LR.

Exception 3

> "Only NSR SCs containing liquid or steam are considered to pose any potential for spatial interaction. NSR SCs containing gases (e.g., plant air systems, ventilation systems) pose no potential for aging effects on SR SCs due to leakage of air or gas.
>
> - NSR portions of plant air systems (instrument air, service air) are not in-scope per this exception.
>
> - NSR portions of ventilation systems are not in-scope per this exception.
>
> - NSR portions of gas systems (nitrogen, hydrogen) are not in-scope per this exception.
>
> - NSR portions of systems that are normally vented or connected to the vent header are not in-scope per this exception."

Exception 3 remains applicable for SLR. Exception 3 is consistent with Appendix F to Rev. 6 of NEI 95-10, which states there are no credible aging mechanisms for air/gas systems with dry internal environments. Additionally, components containing air/gas cannot adversely affect safety-related SSCs due to leakage or spray. Therefore, these systems are not considered to be in scope for 10 CFR 54.4(a)(2) for SLR.

Exception 4

> “Abandoned or manually isolated and drained NSR SCs are not considered to pose any potential for aging effects on SR SCs, and therefore do not need to be in-scope.
>
> - NSR glycol drain tank in G-03/G-04 emergency diesel generator rooms is manually isolated, vented and drained when the engine is operational, and therefore is not in-scope per this exception.”

This exception remains applicable for SLR as current plant procedures and drawings confirm that the glycol drain tanks remain isolated, vented and drained during EDG Operation.

> - “NSR portions of the heating steam system that are isolated and control tagged as abandoned are not in-scope per this exception.”

For SLR, a review of current PBN SLR boundary drawings and P&IDs for the heating steam system identified only one component that is abandoned. This component was abandoned by physically disconnecting and capping the component from the remainder of the system consistent with Method 2 described in Section 2.1.4.2.4 of this report. Therefore, this exception is not required for SLR.

Exception 5

> “Spray is not postulated from unpressurized systems, however leakage still is a potential. Leakage can only affect SR SCs that are physically below the unpressurized NSR components. If SR components are above or beside the unpressurized NSR components, the NSR components would not need to be in-scope.
>
> - NSR chemical addition pots in the auxiliary feedwater pump rooms are normally vented and isolated and are mounted near the floor where they cannot leak on any SR equipment; therefore, these chemical addition pots are not in-scope.”

This exception remains applicable for SLR. The chemical addition pots are located in the standby steam generator feedwater pump cubicles. Walkdowns show they are located close to the floor and cannot spray onto or damage any SR equipment in the area. A walkdown of the SR turbine driven auxiliary feedwater pump cubicles was completed and verified there were no chemical addition pots in the cubicles.

- “A HUT cubicle has some SR piping that passes through this cubicle and exits the ceiling to supply SR components in a cubicle above. NSR piping that is above or adjacent to this SR piping has been included in-scope, but the HUT tank itself is at very low pressure (normally 2.5 psig) and as such it could not spray on the SR piping, and therefore the A HUT is not in scope.”

This exception remains applicable for SLR. The A HUT continues to operate at very low pressure and the potential for adverse interaction with SR equipment due to spray or leakage does not exist.

Exception 6

> “NSR SCs in large open areas (e.g., turbine building, facade) are eliminated from scope if it can be shown that there is no possible effect on the SR SCs.
>
> - The NSR reactor makeup water (RMW) Tank is on the 6.5' elevation of the facade. This tank is not pressurized. This tank is about 1/3 the size of the refueling water storage tank (RWST), and therefore is bounded by the flooding analysis that assumed the RWST would fail. There are also two short runs of pressurized pipe (- 5' long) where the pipe exits the adjacent RMW pump room and crosses into the primary auxiliary building (PAB). Intervening structures exist between these pipes and any SR equipment (nearest would be the containment penetrations on 26' elevation). Failure of any of these RMW components on the 6.5' elevation could not affect any SR equipment, and therefore these NSR components are not in-scope.”

This exception is not required for SLR. As stated in Section 2.1.4.2.1 above, the NSR reactor makeup water tank provides an emergency backup source of water to the component cooling water system surge tanks to accommodate leakage from the component cooling water loops and is in-scope for SLR.

- “SR crossover steam dump components are located within the 66ft. fan room. SR equipment in the 66ft. fan room includes SG pressure transmitters and the main steam lines themselves (in the overhead). The transmitters are environmental qualification (EQ) qualified for harsh environment based on main steam line break potential, and this bounds the energy level of the crossover steam dump system by a significant margin. The crossover steam dump components are a minimum of 50' away from SR equipment and failure of these NSR components will not affect the function of these SR components. Therefore, the NSR crossover steam dump components would not be in-scope.”

This exception remains applicable for SLR. The crossover steam dumps are located in the 66 ft. plant auxiliary building fan rooms. Walkdowns of the area were completed and confirmed there is no SR equipment in the area.

- “The SR main feedwater regulating valves (MFRVs), bypass valves, and associated solenoid operated valves (SOVs), are located on the 26' elevation of the Unit 1/Unit 2 turbine building. The safety function is for the MFRVs and bypass valves to close. The SOVs are EQ qualified for harsh environments. The piping on either end of these valves is NSR. All other equipment on this elevation of the turbine building is NSR. The only potential failure that could cause a failure of the safety function of these components, would be a flow accelerated corrosion (FAC) failure where a pipe-whip impact could bend the actuator stem and prevent the valve from closing. Simple leakage or spray would not affect the safety function of these valves, as external aging effects would only create fail-safe failures of the SR valves (through-wall leakage would divert flow from SGs which is the fail-safe direction). Therefore, NSR high energy piping sections that pose the potential for pipe-whip on these valves and/or SOVs are included in-scope. Portions of high energy piping that cannot physically reach, or are shielded from, the SR components by structures or other larger piping, are not included in-scope. Major components such as feedwater heaters and the condenser are anchored and do not have the potential for pipe-whip, and therefore are also not included in-scope."

This exception remains applicable for SLR. The PBN EPU project added SR main feedwater isolation valves (MFIVs) to minimize mass and energy releases inside the containment following a main steam line break (MSLB). The MFIVs are located downstream of the feedwater control and valves and close to the containment penetrations. As discussed in Section 2.3.4.2, there are several components of the feedwater and condensate system that are in-scope for 10 CFR 54.4(a)(2) to prevent adverse interaction with the SR MFIVs.

The SLR walkdown report also includes a review of NSR mechanical systems not originally in-scope for the original PBN LR. This review was focused on determining if SR equipment had been added and located in the proximity of these NSR systems requiring them to be in-scope for SLR per 10 CFR 54.4(a)(2). This review did not identify any plant changes since the original LR that would have added these NSR to the scope of SLR.

Each mechanical system within the scope of SLR was reviewed to confirm that nonsafety-related SSCs within the system that meet the criteria of 10 CFR 54.4(a)(2) are in scope. The details of these reviews are included in each of the in-scope mechanical system screening and AMR reports.

2.1.4.2.4. Abandoned Equipment

There are mechanical fluid components at PBN that have been abandoned. Abandoned piping components within structures containing safety-related components were excluded from scope when the following conditions were met:

(1) The abandoned piping components do not provide structural or seismic support to attached safety-related piping, and

(2) The abandoned piping is separated from sources of water by blanks, blind flanges or pipe caps. Closed valves are not credited to keep fluid from abandoned components, and

(3) The abandoned piping is empty of fluid. Piping was verified to be empty by establishing configuration (such as the piping being open-ended at the low point), by review of documents that abandoned the equipment, or by other methods that is capable of confirming the absence of trapped fluid.

The above conditions are ensured by implementation of the PBN abandoned equipment administrative procedure.

The structural integrity of abandoned equipment is managed consistent with the plant "spaces" approach that assumes a spatial interaction can occur if safety-related and nonsafety-related (or abandoned) SSCs are located within the same space. This approach is discussed in Section 2.1.4.2.3.

2.1.4.3. Regulated Events – 10 CFR 54.4(a)(3)

In accordance with 10 CFR 54.4(a)(3), the SSCs within the scope of license renewal include:

> *All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).*

This report identifies the systems and structures required to demonstrate compliance with each of the regulated events. The report also includes references to source documents used to determine the scope of components within a system that are credited to demonstrate compliance with each of the applicable regulated events. SSCs credited in the regulated events have been classified as satisfying criteria of 10 CFR 54.4(a)(3) and have been included within the scope of SLR.

2.1.4.4. System and Structure Intended Functions

For the systems and structures within the scope of SLR, the intended functions that are the bases for including them within the scope are identified during the scoping process and documented in the individual systems and structures screening and AMR results presented in Section 2.3, 2.4 and 2.5. Intended functions define the plant process or condition that must be accomplished in order to perform or support a critical safety function for responding to a DBE or to perform or support a specific requirement of one or more of the five regulated events in 10 CFR 54.4(a)(3). At the major system/structure level, the intended function may be thought of as the reason a system or structure is included within the scope of SLR. For example, the safety injection (SI) system is considered to be in the scope of SLR because it is required to perform the intended function of delivering borated cooling water to the reactor coolant system during the injection phase of a loss of coolant accident (LOCA) to support core cooling. The ultimate goal of intended function identification is to provide a basis for determination of structures and components requiring an AMR in accordance with 10 CFR 54.21(a). The identification of the specific component/structure intended functions supporting the system's intended function is performed as part of the screening process as described in Section 2.1.5.

2.1.4.5. Scoping Boundary Determination

Systems and structures that are included within the scope of SLR are then further evaluated to determine the populations of in scope structures and components. This part of the scoping process is also a transition from the scoping process to the screening process. The process for evaluating mechanical systems is different from the process for structures, primarily because the plant design document formats are different. Mechanical systems are depicted primarily on the system piping and instrumentation diagrams (P&IDs) that show the system components and their functional relationships, while structures are depicted on physical drawings. Electrical and I&C components of in scope electrical and in scope mechanical systems are placed in commodity groups and are screened as commodities. The determination of SLR system and structure boundaries are further described in the screening procedures for mechanical systems (2.1.5.1), civil structures (2.1.5.2), and electrical and I&C systems (2.1.5.3).

2.1.5. Screening Methodology

This section discusses the screening process used at PBN to determine which components and structural components (collectively abbreviated as SCs) are in the scope of SLR and require an AMR.

The requirement to identify SCs subject to an AMR is specified in 10 CFR 54.21(a)(1):

Each application must contain the following information:

(a) An integrated plant assessment (IPA). The IPA must--

(1) For those systems, structures, and components within the scope of this part, as delineated in §54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components--

(i) That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

(ii) *That are not subject to replacement based on a qualified life or specified time period.*

For SLR, SCs that perform an intended function without moving parts or without a change in configuration or properties are defined as passive. For SLR, passive SCs that are not subject to replacement based on a qualified life or specified time period are defined as long-lived. The screening procedure is the process used to identify passive, long-lived SCs that are in the scope of SLR and are subject to an AMR.

This portion of the PBN IPA methodology is divided into three engineering disciplines: mechanical, civil/structural, and electrical/I&C. The relevant aspects of the component/structural component scoping and screening process for mechanical systems, civil structures, and electrical and I&C systems are described in Section 2.1.5.1, Section 2.1.5.2, and Section 2.1.5.3, respectively. A statement regarding how the SLR boundaries compare to current license renewal boundaries is included in the “Boundary” discussion in each of the individual systems and structures screening and AMR results in presented in Sections 2.3, 2.4, and 2.5. For the systems and structures where the boundaries have not changed, a statement is made that there are no significant differences. The word “significant” is utilized to clarify that there may be minor differences within the boundaries (e.g., valve numbering, locations of vents and drains, etc.), but that the overall boundaries have not changed for SLR.

For mechanical systems and civil structures, this process establishes evaluation boundaries, determines the SCs that comprise the system or structure, determines which of those SCs support system/structure intended functions, and identifies specific SC intended functions. Consequently, not all of the SCs for in-scope systems or structures are in the scope of SLR because some of the components in a system or structure are outside the evaluation boundaries for SLR. Once these in-scope SCs are identified, the process then determines which SCs are subject to an AMR per the criteria of 10 CFR 54.21(a)(1).

For electrical and I&C systems, a component/commodity based approach as described in NEI 17-01 is taken. This approach establishes component/commodity evaluation boundaries, determines the electrical and I&C component commodity groups that compose in-scope systems, identifies specific component and commodity intended functions, and then determines which component commodity groups are subject to an AMR per the criteria of 10 CFR 54.21(a)(1). This approach calls for component/commodity level scoping after screening has been performed.

Table 2.1.5-1 provides the definitions of mechanical system, civil structure, and electrical and I&C system component intended functions used for components and structures.

2.1.5.1. Mechanical Systems

For mechanical systems, the component screening process is performed on each mechanical system identified to be within the scope of SLR. This process evaluates the individual SCs included within in-scope mechanical systems to identify specific SCs or SC groups that require an AMR. Each in scope mechanical system is evaluated in a screening and AMR technical report. These mechanical systems in the scope of SLR are grouped into one of the following categories:

- Reactor Vessel, Internals and Reactor Coolant System
- Engineered Safety Features
- Auxiliary Systems
- Steam and Power Conversion Systems

Where appropriate, multiple mechanical systems were included in a single screening and AMR technical report. Examples of this include the multiple ventilation systems included in the essential ventilation system screening and AMR technical report, diesel fuel oil and diesel starting air systems addressed in the single emergency power system screening and AMR technical report, and multiple systems included in the treated water system screening and AMR technical report.

Mechanical system evaluation boundaries were established for each system within the scope of SLR. These boundaries were determined by mapping the pressure boundary associated with the SLR system intended functions onto the system P&IDs. The boundary drawings also include in scope components that may not have a mechanical pressure boundary intended function. SLR system intended functions are the functions a system must perform relative to the scoping criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3). The boundary drawings associated with each mechanical system within the scope of SLR are identified with the mechanical system screening results described in Section 2.3.

The sequence of steps performed on each mechanical system determined to be within the scope of SLR is as follows:

- Identify all SCs within that system based on design drawings, original license renewal documents, and the system component list from the NAMS component database.

- Define system evaluation boundaries and eliminate SCs not within the scope of SLR (i.e., not required to perform system intended functions). The system intended function boundaries include those portions of the system that are necessary to ensure that the intended functions of the system are performed.

- Nonsafety-related mechanical components and piping segments beyond the safety-related/nonsafety-related boundaries that have the intended function of ensuring structural integrity of the attached safety-related components under CLB design loading conditions are not explicitly indicated on the SLR boundary drawings but are in the scope of SLR per 10 CFR 54.4(a)(2).

- In addition, nonsafety-related SCs not directly connected to safety-related SCs whose failure could prevent the performance of a safety-related system intended function are in the scope of subsequent license renewal per 10 CFR 54.4(a)(2). The concern is that age-related degradation of the nonsafety-related SCs could adversely impact nonsafety-related SCs through spatial interaction. The nonsafety-related SCs are highlighted on the applicable SLR boundary drawings and are documented in the relevant screening and AMR technical report.

- Components needed to support each of the system-level intended functions identified in the scoping process must be included within the system intended function boundaries. The screening and aging management review of the supports for mechanical components (e.g. piping supports, mechanical equipment foundations, etc.) is performed in Section 2.1.5.2 as part of civil structures.

- The primary method of designating the system intended function boundaries is to identify the boundaries on system P&IDs. The basis for not including a component that is assigned to the system and within the subsequent license renewal boundary is explained in the screening and AMR technical report.

- Identify SCs that perform their intended functions in a passive manner and thus allow elimination of all active SCs. Valve bodies, fan housings and pump casings may perform an intended function by maintaining the system pressure boundary and, therefore, would be subject to AMR.

- Identify long-lived SCs that allow for elimination of all short-lived (replaceable) SCs. The long-lived/short-lived determination is only required for those SCs that are within the scope of SLR. If the component is not subject to replacement based on a qualified life or specified time period, then it is considered long-lived. Components that are not long-lived do not require an aging management review.

- Components within the system intended function boundaries that are both passive and long-lived are identified as subject to AMR in each of the mechanical system screening and AMR technical report.

With regard to thermal insulation on mechanical components, a screening review was performed as part of the original PBN license renewal project. The review identified only two locations where piping thermal insulation was considered to be in scope of LR. Insulation is installed on the main steam and main feedwater piping at the containment penetrations, and is needed to maintain steady-state concrete temperatures less than 150 degrees F. Therefore, thermal insulation for the main steam and feedwater penetrations is included in the scope of SLR and is addressed in Section 2.4.

Based on a review of modifications performed since the original PBN license renewal, no changes have occurred that would add additional insulation into the scope of SLR. PBN ensures building temperatures are maintained within normal operating environmental qualification design limits and takes specific corrective action if a condition occurs that would challenge those temperatures. Additionally, adverse localized environments are addressed as part of the Environmental Qualification aging management program in Section B.2.2.4 and the Electrical Insulation for Electrical Cables and Connections not Subject to 10 CFR 50.49 EQ Requirements AMP in Section B.2.3.37.

Some mechanical components, when combined, are considered complex assemblies. A complex assembly is a predominantly active assembly where the performance of its components is closely linked to the intended function of the entire assembly, such that testing and monitoring of the assembly is sufficient to identify degradation of the components. Examples of complex assemblies at PBN include the emergency diesel generators, chiller units, compressors that are part of direct expansion cooling units, and air compressor skids. However, to the extent that complex assemblies include piping or components that interface with external equipment, or components that cannot be adequately tested or monitored as part of the complex assembly, those components are identified and subject to AMR. The boundaries identified for each complex assembly are detailed in their respective screening and AMR technical reports. This follows the screening methodology for complex assemblies as described in Table 2.1-2 of NUREG-2192.

2.1.5.2. Civil Structures

For structures, the screening process is performed on each structure identified to be within the scope of SLR consistent with original license renewal. This method evaluates the SCs included within in-scope structures to identify SCs or SC groups (commodities) that are subject to an AMR. Each in scope structure and SC is evaluated in a screening and AMR technical report. The structures in the scope of SLR are grouped into one of the following categories:

- Containment Building Structure
- Plant Structures

The sequence of steps performed on each structure determined to be within the scope of SLR is as follows:

- Based on a review of design drawings, the structure component list from the NAMS component database, and plant walkdowns, SCs that are included within the structure are identified. These SCs include items such as walls, floors, foundations, supports, and electrical and I&C components, (e.g., conduit, cable trays, electrical enclosures, instrument panels, and related supports).

- The SCs that are within the scope of SLR (i.e., required to perform a SLR system intended function) are identified.

- Design features and associated SCs that prevent potential seismic interactions for in-scope structures housing both safety-related and nonsafety- related systems are identified. This includes a walkdown of each plant area containing both safety-related and nonsafety-related SSCs.

- Component intended functions for in-scope SCs are identified. The component intended functions identified are based on the guidance of NEI 17-01.

- The in-scope SCs that perform an intended function without moving parts or without a change in configuration or properties (screening criterion of 10 CFR 54.21(a)(1)(i)) are identified.

- The passive, in-scope SCs that are not subject to replacement based on a qualified life or specified time period (screening criterion of 10 CFR 54.21(a)(1)(ii)) are identified as requiring an AMR. The determination of whether a passive, in-scope SC has a qualified life or specified replacement time period was based on a review of plant-specific information, including the NAMS component database, maintenance programs and procedures, vendor manuals, and plant operating experience.

2.1.5.3. Electrical and I&C Systems

The method used to determine which electrical and I&C components are subject to an AMR is organized based on component commodity groups. The primary difference in this method versus the one used for mechanical systems and civil structures is the order in which the component scoping and screening steps are performed. This method was selected for use with the electrical and I&C components since most electrical and I&C components are active. Thus, the method selected provides the most efficient means for determining electrical and I&C components that require an AMR. The method employed is consistent with the guidance in NEI 17-01.

The sequence of steps for identification of electrical and I&C components that require an AMR is as follows:

- Electrical and I&C component commodity groups associated with electrical, I&C, and mechanical systems within the scope of SLR are identified. This step includes a review of design drawings and electrical and I&C component commodity groups in the NAMS component database.

- A description and function for each of the electrical and I&C component commodity groups are identified.

- The electrical and I&C component commodity groups that perform an intended function without moving parts or without a change in configuration or properties (screening criterion of 10 CFR 54.21(a)(1)(i)) are identified.

- For the passive electrical and I&C component commodity groups, component commodity groups that are not subject to replacement based on a qualified life or specified time period (screening criterion of 10 CFR 54.21(a)(1)(ii)) are identified as requiring an AMR. Electrical and I&C component commodity groups covered by the 10 CFR 50.49, Environmental Qualification program, are considered to be subject to replacement based on qualified life.

- Certain passive, long-lived electrical and I&C component commodity groups that do not support SLR system intended functions are eliminated.

2.1.5.4. Intended Function Definitions

The intended functions that the components and structures must fulfill are those functions that are the bases for including them within the scope of SLR. A component intended function is defined as specific component functions, performed by passive long-lived components and structural elements, that support system and structure intended functions. Examples of component intended functions are maintain pressure boundary, support safety-related equipment, and insulate electrical conductors. Structures and components may have multiple intended functions. PBN has considered multiple intended functions where applicable, consistent with the staff guidance provided in Table 2.1-3 of NUREG-2192.

Table 2.1.5-1 provides expanded definitions of structure and component passive intended functions identified for the PBN SLR project.

Table 2.1.5-1
Passive Structure/Component Intended Function

Intended Function	Definition
Electrical continuity	Provide electrical connections to specified sections of an electrical circuit to deliver voltage, current or signals
Direct flow	Provide spray shield or curbs for directing flow or provide means of fluid flow diversion within a component (as seen in divider plates, heat exchanger coil shields, vortex diffusers, etc.).
Filter	Provide filtration
Fire barrier	Provide rated fire barrier to confine or retard a fire from spreading between adjacent areas of the plant
Fire prevention	Confine or retard a fire from spreading
Flood barrier	Provide flood protection barrier for internal or external flooding
Flow distribution	Provide a passageway for the distribution of the reactor coolant flow to the reactor core
HELB shielding	Provide shielding against high energy line breaks
Heat sink	Provide heat sink during design basis accidents
Heat transfer	Provide heat transfer
Insulate (electrical)	Insulate and support an electrical conductor
Insulate (thermal)	Inhibit/prevent heat transfer across a thermal gradient
Insulation jacket integrity	Protect insulation to maintain its insulating capability
Leakage boundary(spatial)	NSR components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of SR SSCs
Maintain adhesion	Provide ECCS sump debris protection by remaining attached to the applied surfaces
Mechanical closure	Provide closure of components, typically used with bolting
Missile barrier	Provide missile barrier (internally or externally generated)
Pipe whip restraint	Provide pipe whip restraint
Pressure boundary	Provide pressure-retaining boundary or essentially leak tight barrier so that sufficient flow at adequate pressure is delivered, or provide fission product barrier for containment pressure boundary, or provide containment isolation for fission product retention
Radiation shielding	Provide shielding against radiation
Shelter, protection	Provide shelter/protection to in scope components
Spray	Convert fluid into spray
Structural integrity (attached)	NSR components that maintains mechanical and structural integrity to provide structural support to attached SR SSCs
Structural support	Provide structural and/or functional support to SR and/or NSR components
Throttle	Provide flow restriction

2.1.5.5. Stored Equipment

The PBN CLB does not take credit for stored equipment or making repairs to equipment that meet the scoping criteria identified in 10 CFR 54.4(a). For fire protection safe shutdown, the PBN NFPA 805 Nuclear Safety Capability Assessment represents the fire safe shutdown analysis (SSA). That report and the NFPA 805 manual actions feasibility evaluation were reviewed and confirmed that the PBN fire protection program does not take credit for post-fire repair of plant equipment or use of stored equipment. As such, there are no stored components or equipment included within the scope of SLR.

2.1.5.6. Consumables

The evaluation process for consumables is consistent with the guidance provided in NUREG-2192, Table 2.1-3. Consumables have been divided into the following four groups for the purpose of SLR: (1) packing, gaskets, component seals and O-rings; (2) structural sealants; (3) oil, grease, and component filters; (4) system filters, fire extinguishers, fire hoses, and air packs.

- Group (1) subcomponents (packing, gaskets, component seals, and O-rings): Per NUREG-2192, Table 2.1-3, these consumables are considered subcomponents and are not explicitly called out in scoping and screening procedures. They are included at the component level (i.e. seals for in scope valves are included as subcomponents of said valves). These subcomponents are not relied upon for the performance of any SLR intended functions under 10 CFR 54; therefore, these items are not considered within the scope of SLR and are not subject to an AMR.

- Group (2) structural sealants: Structural sealants are treated as subcomponents of their associated structure. These consumables are not called out explicitly in scoping and screening and are implicitly addressed in the Structures Monitoring AMP presented in Section B.2.3.34.

- Group (3) subcomponents (oil, grease, and component filters): Subcomponents in this group are short-lived and periodically replaced. Various plant procedures are used in the replacement of oil, grease, and filters in components that are in the scope of subsequent license renewal. As these subcomponents are not considered long- lived, they are not subject to an AMR.

- Group (4) consumables (system filters, fire extinguishers, fire hoses, and air packs): System ventilation filters, fire extinguishers, fire hoses, nitrogen cylinders, halon cylinders, and air packs are within the scope of SLR but are not subject to aging management because they are replaced based on measured degradation in performance or condition replacement criteria specified in applicable codes, technical specifications, or site approved programs as described in the fire protection screening and AMR technical report.

2.1.6. <u>Interim Staff Guidance Discussion</u>

As discussed in NEI 17-01, the NRC has encouraged applicants to address Subsequent License Renewal Interim Staff Guidance (SLR-ISG) documents in the Subsequent License Renewal Applications (SLRA). The following draft SLR-ISGs have been issued for use and comment but have not been incorporated in NUREG-2191 or NUREG-2192 at the time of submittal:

- SLR-ISG-Electrical-2020-XX (Reference ML20156A324) — Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance
- SLR-ISG-Structures-2020-XX (Reference ML20156A338) — Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance
- SLR-ISG-Mechanical-2020-XX (Reference ML20156A330) — Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance

The following sub-sections provide summaries of how each of the SLR-ISGs are addressed in the SLRA.

2.1.6.1. Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance (SLR-ISG-Electrical-2020-XX)

This SLR-ISG provides interim guidance to subsequent license renewal applicants for the following NUREG-2191 and NUREG-2192 Sections:

- XI.E3A/B/C, Electrical Insulation for Inaccessible Medium Voltage/Instrument and Control/Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

  The proposed revisions to XI.E3A/B/C allow for a 5-year inspection of manholes with water level monitoring and alarms that result in consistent, subsequent pump out of accumulated water prior to wetting or submergence of cable, as supported by plant operating experience. Also, the inspection of manholes following event-driven occurrences such as heavy rain, rapid thawing of ice and snow, or flooding, is only recommended when water level monitoring indicates water is accumulating.

  Although the PBN Electrical Insulation for Inaccessible Medium-Voltage Cables not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.39) AMP, the PBN Electrical Insulation for Inaccessible Instrumentation and Control Cables not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.40) and AMP the PBN Electrical Insulation for Inaccessible Low-Voltage Power Cables not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.41) AMP incorporate the guidance in this SLR-ISG, PBN manholes are not equipped with continuous level monitoring (such as an ultrasonic level monitoring system with alarms). Therefore, since the plant does not have real-time level monitoring in manholes and plant operating experience (OE) does not support a 5-year inspection of manholes, PBN does not intend to implement a 5-year inspection of manholes or eliminate the inspection of manholes following event-driven occurrences such as heavy rain, rapid thawing of ice and snow, or flooding. Consistent with NUREG-2191, XI.E3A/B/C AMP inspections for PBN will be performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the SPEO. Inspection frequencies will be adjusted based on inspection results, including site-specific OE, but with a minimum inspection frequency of at least once annually. Inspections will also be performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.

- XI.E7, High Voltage Insulators

  The proposed revision to XI.E7 adds polymer and toughened glass high-voltage insulators to the scope and program elements and includes all insulators operating at or above 4 kV.

  Although the PBN High Voltage Insulators (B.2.3.44) AMP incorporates the guidance presented in this SLR-ISG, PBN does not have polymer or toughened glass high-voltage insulators or any medium-voltage insulators within the scope of subsequent license renewal. Therefore, this proposed revision to XI.E7 is not applicable to PBN.

2.1.6.2. Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance (SLR-ISG-Structures-2020-XX)

This SLR-ISG provides interim guidance to subsequent license renewal applicants for the following NUREG-2191 and NUREG-2192 Sections:

- XI.S8, Protective Coating Monitoring and Maintenance

  The AMP revises the frequency of inservice coating inspection monitoring to no later than 6 years based on trending of the total amount of permitted degraded coatings and adopts Revision 3 to Regulatory Guide 1.54. Although the PBN Coating Monitoring and Maintenance (B.2.3.36) AMP and UFSAR Supplement (16.2.2.36) incorporate the guidance presented in this SLR-ISG, the inspections at PBN for this AMP will continue to be performed each refueling outage.

- NUREG-2192 Section 3.5 (Fatigue Waiver)

  An option is provided to perform a further evaluation based on American Society of Mechanical Engineers (ASME) Code, Section III, Division 1, Subsection NE, fatigue waiver analysis for containment metallic pressure-retaining boundary components that are subject to cyclic loading but have no current licensing basis (CLB) fatigue analysis. If the ASME Code fatigue waiver acceptance criteria are met then cracking due to cyclic loading does not require aging management. As discussed in Section 3.5.2.2.1.5 and Section 4.6, PBN has not identified fatigue waiver analysis for containment metallic pressure-retaining boundary components that are subject to cyclic loading but have no current licensing basis (CLB) fatigue analysis. As such, cumulative fatigue damage (cyclic loading evidenced as cracking) for non-piping penetrations will be managed for SLR by the ASME Section XI, Subsection IWE (B.2.3.29) AMP and the 10 CFR Part 50, Appendix J (B.2.3.32) AMP.

- NUREG-2191 and NUREG-2192

  NUREG-2191 Chapters II and III and NUREG-2192, Table 3.5-1 are modified to reflect the option of using plant-specific enhancements to GALL-SLR XI.S2 (B.2.3.30) and XI.S6 (B.2.3.34) AMPs to manage effects of aging in concrete in lieu of recommended plant-specific aging management programs. Further evaluation and AMR lines are provided in Section 3.5, Aging Management of Containments, Structures and Component Supports.

2.1.6.3. Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance (SLR-ISG-Mechanical-2020-XX)

This SLR-ISG provides interim guidance to subsequent license renewal applicants for the following NUREG-2191 and NUREG-2192 Sections:

- X.M2, Neutron Fluence Monitoring

  The AMP was revised to reference approaches that have been found to be acceptable in recent staff reviews of extended beltline and reactor vessel internals fluence calculations, as RG 1.190 is not applicable. The PBN Neutron Fluence Monitoring (B.2.2.2) AMP incorporates the guidance presented in the SLR-ISG.

- XI.M2, Water Chemistry

  The AMP and UFSAR Supplement are revised to include the latest revision of EPRI guidelines for BWRs and PWRs. The PBN Water Chemistry (B.2.3.2) AMP and UFSAR Supplement (16.2.2.2) incorporate the guidance presented in this SLR-ISG.

- XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

  This AMP was revised to add the 2019 Edition of ASME Code, Section XI, Non-mandatory Appendix C, which provides flaw evaluation procedures for CASS with ferrite content ≥ 20 percent. The PBN Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B.2.3.6) AMP incorporates the guidance presented in this SLR-ISG.

- XI.M21A, Closed Treated Water System

  The AMP was revised to include the latest revision of EPRI closed cooling water chemistry guidelines. The PBN Closed Treated Water System (B.2.3.12) AMP and UFSAR Supplement (16.2.2.12) incorporates the guidance presented in this SLR-ISG.

- XI.M26, Fire Protection

  This SLR-ISG adds new fire barrier AMR items VII.G.A-805, VII.G.A-806 and VII.G.A-807 to NUREG-2191, Table VII.G, “Fire Protection” and makes conforming changes to NUREG-2192, Table 3.3-1. AMR lines have been provided in Section 3.5, Aging Management of Containments, Structures and Component Supports.

- NUREG-2191 Table VII.H2, Emergency Diesel Generator System

  The SLR-ISG revises NUREG-2191, Table VII.H2 "Emergency Diesel Generator System" and makes conforming changes to NUREG-2192, Table 3.3-1 to include line items to manage the reduction of heat transfer for a steel heat exchanger radiator exposed internally to diesel fuel oil and include a line item for managing loss of material for nickel alloy externally exposed to diesel fuel oil. These AMR lines are not applicable for PBN.

- XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers and Tanks

  The AMP was revised to recommend opportunistic inspections, in lieu of periodic inspections, as an acceptable alternative for buried internally coated/lined fire water piping if certain conditions are met. The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers and Tanks (B.2.3.28) AMP incorporates the guidance presented in the SLR-ISG.

2.1.7. <u>Generic Safety Issues</u>

In accordance with the guidance in NEI 17-01 and NUREG-2192, review of NRC generic safety issues (GSIs) as part of the SLR process is required to satisfy a finding per 10 CFR 54.29. GSIs designated as unresolved safety issues (USIs) and High- and Medium-priority issues in NUREG-0933, Appendix B, that involve aging effects for structures and components subject to an AMR or TLAA evaluations, are to be addressed in the SLRA. A review of the version of NUREG-0933 current six months prior to the SLRA submittal determined that there were no outstanding USIs or High- or Medium-priority GSIs. The GSIs noted below were reviewed to assure they did not involve aging effects for structures and components subject to an aging management review or time-limited aging analysis evaluation:

Issue 186, Potential Risk and Consequences of Heavy Load Drops in Nuclear Power Plants, involves issues related to crane design and operation. Aging effects are not central to these issues. Additionally, this issue does not involve TLAA evaluations, including typical crane-related TLAAs such as cyclic loading analyses. This issue is now closed (Reference ML113050589).

Issue 189, Susceptibility of Ice Condenser Containments to Early Failure from Hydrogen Combustion during a Severe Accident, is not applicable to PBN, which does not have ice condenser containments. This issue is now closed (Reference ML13190A244).

Issue 191, Assessment of Debris Accumulation on PWR Sump Performance, addresses the potential for blockage of containment sump strainers that filter debris from cooling water supplied to the safety injection and containment spray pumps following a postulated LOCA. The issue is based on the identification of new potential sources of debris, including failed containment coatings, which may block the sump strainers. The containment sump strainers (screens) are evaluated with the residual heat removal system as described in Section 2.3.2.3. The Service Level 1 protective coatings inside containment are evaluated with the containment structure and internal structural components as described in Section 2.4.1. The issue is not related to the 60-year term of the current operating license; and, therefore, it is not a TLAA.

Issue 193, Boiling Water Reactor (BWR) ECCS (Emergency Core Cooling Systems) Suction Concerns, addresses the possible failure of low-pressure ECCSs due to unanticipated, large quantities of entrained gas in the suction piping from suppression pools in BWR Mark I containments. This issue is not applicable to PBN, which is a PWR. This issue is closed (Reference ML16082A288).

Issue 199, Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States, addresses how current estimates of the seismic hazard level at some nuclear sites in the central and eastern United States might be higher than the values used in their original designs and previous evaluations. Aging effects are not central to this issue. This issue does not involve time-limited aging analyses. Activities associated with this issue are covered by 10 CFR 50.54(f) Japan Near Term Task Force (NTTF) Recommendations.

Issue-204, Flooding of Nuclear Power Plant Sites Following Upstream Dam Failures, addresses the potential flooding effects from upstream dam failure(s) on nuclear power plant sites, spent fuel pools, and sites undergoing decommissioning with spent fuel stored in spent fuel pools. Aging effects are not central to this issue. This issue does not involve time-limited aging analyses. Activities associated with this issue are covered by 10 CFR 50.54(f) Japan Near Term Task Force (NTTF) Recommendations.

Thus, there are no GSIs involving aging effects for structures and components subject to an AMR or TLAA evaluations that are relevant to the PBN SLR process.

2.1.8. Conclusion

The scoping and screening methods described in Sections 2.1.4 and 2.1.5 above were used for the PBN Units 1 and 2 SLR IPA to identify the SSCs that are within the scope of SLR and require an AMR. These methods are consistent with and satisfy the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2. PLANT LEVEL SCOPING RESULTS

PBN's IPA methodology consists of scoping, screening, and AMRs. Table 2.2-1 lists the PBN systems, structures and commodity groups that were evaluated to determine if they were within the scope of subsequent license renewal, using the methodology described in Section 2.1. A reference to the section of the application that contains the scoping and screening results is provided for each in-scope mechanical system, structure, and electrical system in the Table.

Table 2.2-1
Plant Level Scoping Reports

SLRA System Name	PBN System Name	PBN System Designator	In Scope for Subsequent License Renewal	Reference
Reactor Vessel, Internals, and Reactor Coolant System				
Reactor Vessel	Reactor Coolant	RC	Yes	2.3.1.1
Reactor Vessel Internals	Reactor Coolant	RC	Yes	2.3.1.2
Pressurizer	Reactor Coolant	RC	Yes	2.3.1.3
Reactor Coolant and Connected Piping	Reactor Coolant	RC	Yes	2.3.1.4
Steam Generators	Reactor Coolant	RC	Yes	2.3.1.5
Engineered Safety Features				
Safety Injection	Safety Injection	SI	Yes	2.3.2.1
Containment Spray	Safety Injection	SI	Yes	2.3.2.2
Residual Heat Removal	Residual Heat Removal	RH	Yes	2.3.2.3
Containment Isolation Components	Demineralized Water	DI	Yes	2.3.2.4
	Containment Penetrations	CP	Yes	2.3.2.4
Auxiliary Systems				
Chemical and Volume Control	Chemical and Volume Control	CV	Yes	2.3.3.1
	Gas Stripper (Letdown)	GS	Yes	2.3.3.1
	Boron Recycle	BS	Yes	2.3.3.1
	Reactor Makeup Water	RMW	Yes	2.3.3.1
Component Cooling Water	Component Cooling Water	CC	Yes	2.3.3.2
	Radwaste Systems Component Cooling Water	CC	Yes	2.3.3.2
Spent Fuel Cooling	Spent Fuel Cooling and Filtration	SF	Yes	2.3.3.3
Waste Disposal	Waste Gas	WG	Yes	2.3.3.4
	Waste Liquid	WL	Yes	2.3.3.4
	Hydrogen Gas	HG	No	N/A
	Nitrogen Gas	NG	No	N/A
	Cryogenic	CR	No	N/A
	Waste Solid	WS	No	N/A
	Blowdown Evaporator and Instruments	BE	No	N/A
Service Water	Service Water	SW	Yes	2.3.3.5
Fire Protection	Fire Protection	FP	Yes	2.3.3.6
Heating Steam	Auxiliary/Heating Steam	HV	Yes	2.3.3.7
Emergency Power	Diesel Generator	DG	Yes	2.3.3.8
	Diesel Starting Air	DA	Yes	2.3.3.8

Table 2.2-1
Plant Level Scoping Reports

SLRA System Name	PBN System Name	PBN System Designator	In Scope for Subsequent License Renewal	Reference
	Gas Turbine	GT	Yes	2.3.3.8
	Fuel Oil	FO	Yes	2.3.3.8
Containment Ventilation	Containment Cooling	VNCC	Yes	2.3.3.9
	Containment Cleanup System	VNCF	No	N/A
	Containment Purge Supply and Exhaust	VNPSE	Yes	2.3.3.9
	Refueling Cavity Ventilation	VNRF	No	N/A
	Control Rod Drive Cooling	VNCRD	No	N/A
	Reactor Cavity Cooling	VNRC	Yes	2.3.3.9
Essential Ventilation	Computer Room HVAC	VNCOMP	Yes	2.3.3.10
	Primary Auxiliary Building Ventilation	VNPAB	Yes	2.3.3.10
	Circulating Water Pump House Ventilation	VNPH	No	N/A
	Radwaste Ventilation	VNRAD	No	N/A
	Control Room Ventilation	VNCR	Yes	2.3.3.10
	Diesel Generator Room Ventilation	VNDG	Yes	2.3.3.10
	Auxiliary Feedwater Pump Area Ventilation	VNAFW	No	N/A
	Battery Room Ventilation	VNBR	No	N/A
	Cable Spreading Room Ventilation	VNCSR	Yes	2.3.3.10
	PAB Battery and Inverter Room Ventilation	VNBI	Yes	2.3.3.10
	Drumming Area Ventilation	VNDRM	No	N/A
	Gas Turbine Building Ventilation	VNGT	Yes	2.3.3.10
Treated Water	Water Treatment	WT	No	N/A
	Demineralized Water	DI	Yes	2.3.3.11
	Potable Water	PW	Yes	2.3.3.11
	Hydrazine Addition	HA	No	N/A
	Sewage Treatment Plant	STP	No	N/A
Circulating Water	Circulating Water	CW	Yes	2.3.3.12
	Chlorination/Dechlorination	CD	Yes	2.3.3.12
Containment Hydrogen Detectors and Recombiner	Post-Accident Containment Ventilation System	PACV	Yes	2.3.3.13
Plant Sampling	Primary Sampling	PS	Yes	2.3.3.14

Table 2.2-1
Plant Level Scoping Reports

SLRA System Name	PBN System Name	PBN System Designator	In Scope for Subsequent License Renewal	Reference
	Secondary Sampling	SS	Yes	2.3.3.14
Plant Air	Service Air	SA	Yes	2.3.3.15
	Instrument Air	IA	Yes	2.3.3.15
	Emergency Breathing Air	EBA	No	N/A
Miscellaneous Ventilation	Warehouse Ventilation	VNWH	No	N/A
	Transporter Storage Building Ventilation	VNTSB	No	N/A
	Training Building HVAC	VNTRN	No	N/A
	Offsite Administrative Building HVAC	VNNES	No	N/A
	Energy Information Center HVAC	VNEIC	No	N/A
	Steam Generator Storage Facility HVAC	VNSGSF	No	N/A
	Site Boundary Control Center HVAC	VNSBCC	No	N/A
	Extension Building HVAC	VNEXT	No	N/A
	Fuel Oil Pump House Ventilation	VNFOPH	No	N/A
	Gatehouse HVAC	VNGH	No	N/A
	Sewage Treatment Plant Ventilation	VNSTP	No	N/A
Non-Essential Ventilation	Turbine Building Office HVAC (Old)	VNTBO	No	N/A
	Maintenance Building HVAC	VNMTN	No	N/A
	Turbine Building Ventilation	VNTB	No	N/A
	South Service Building HVAC	VNSSB	No	N/A
	Technical Support Center Building HVAC	VNTSC	No	N/A
	Water Treatment Area Ventilation	VNWT	No	N/A
	Operations Office HVAC	VNOPS	No	N/A
	Electrical Equipment Room Ventilation	VNEERM	No	N/A
	Boiler Room Ventilation	VNBLR	No	N/A
	North Service Building HVAC	VNNSB	No	N/A
Dry Fuel Storage	Cask Reflooding	CRF	No	N/A
	Cask Dewatering	CDW	No	N/A

Table 2.2-1
Plant Level Scoping Reports

SLRA System Name	PBN System Name	PBN System Designator	In Scope for Subsequent License Renewal	Reference
	Ventilated Storage Cask	VSC	No	N/A
Steam and Power Conversion System				
Main and Auxiliary Steam	Main, Extraction, Gland Seal and Reheat Steam	MS	Yes	2.3.4.1
	Crossover Steam Dump	OS	No	N/A
	Radwaste Steam	RS	Yes	2.3.4.1
Feedwater and Condensate	Condensate and Feedwater	CS	Yes	2.3.4.2
	Radwaste Condensate	RW	No	N/A
	Feedwater Heater and MSR Vents, Reliefs and Drains	FD	Yes	2.3.4.2
Auxiliary Feedwater	Auxiliary Feedwater	AF	Yes	2.3.4.3
Turbine-Generator and Supporting Systems	Independent Overspeed Protection System	IOPS	No	N/A
	Turbine Related	TU	No	N/A
	Electro-Hydraulic Control	EH	No	N/A
	Condenser Air Removal and Priming	AR	No	N/A
	Turbine/Feed Pump Lube Oil and Seal Oil	LO	No	N/A
Containments, Structures, and Component Supports				
Structures	Containment Structure and Internal Structural Components	CONT	Yes	2.4.1
	Containment Penetrations	CP	Yes	2.4.1
	Blowdown Evaporator Building	S	No	N/A
	Circulating Water Pumphouse Structure	S	Yes	2.4.2
	Control Building Structure	S	Yes	2.4.3
	Diesel Generator Building Structure	S	Yes	2.4.4
	Facade Unit 1/2 Structure	S	Yes	2.4.5
	Fuel Oil Pumphouse Structure	S	Yes	2.4.6
	Gas Turbine Building Structure	S	Yes	2.4.7
	Letdown Gas Stripper Building Structure	S	No	N/A

Table 2.2-1
Plant Level Scoping Reports

SLRA System Name	PBN System Name	PBN System Designator	In Scope for Subsequent License Renewal	Reference
	Misc. Nonsafety-related Buildings	S	No	N/A
	Primary Auxiliary Building Structure	S	Yes	2.4.8
	Spent Fuel Pool and Transfer Canal	S	Yes	2.4.9
	Technical Support Center	S	No	N/A
	Turbine Building (Unit 1/2) Structure	S	Yes	2.4.10
	Yard Structures	None	Yes	2.4.11
	13.8kV Switchgear Building Structure	S	Yes	2.4.12
	Component Support Commodity	None	Yes	2.4.13
	Fire Barrier Commodity	FIRPEN	Yes	2.4.14
	Cranes, Hoists, and Lifting Devices	Z	Yes	2.4.15
Electrical and I&C Systems				
120V Vital Instrument Power	Vital Instrument Bus 120V	Y	Yes	2.5
125 VDC Power	125 VDC Electrical	125V	Yes	2.5
480V Power	480 Volt System	480V	Yes	2.5
4160V Power	4160 Volt System	4.16kV	Yes	2.5
13.8kV Power	13,800 Volt System	13.8kV	Yes	2.5
Control Board Annunciators (Not in Scope)	Annunciators	ANN	No	N/A
Control Rod Drive and Indication and Nuclear Process Instrumentation System	Rod Drive Control	RDC	No	N/A
	Rod Position Indication	RPI	No	N/A
	Rod Insertion Limit	RIL	No	N/A
	Incore Flux Mapping	FM	No	N/A
	Nuclear Instrumentation	NI	Yes	2.5
	Rod Speed Control	RSC	No	N/A
Engineered Safety Features Actuation	Engineered Safety Features	ESF	Yes	2.5
Miscellaneous AC Power and Lighting	120 Volt Lighting	120V	No	N/A
	240V Electrical	240V	No	N/A
	208 Volt Lighting	208Y	No	N/A
	Façade Freeze Protection	FF	Yes	2.5

Table 2.2-1
Plant Level Scoping Reports

SLRA System Name	PBN System Name	PBN System Designator	In Scope for Subsequent License Renewal	Reference
	Emergency Lighting	ELLTG	Yes	2.5
	Boric Acid Heat Tracing	BA	No	N/A
	Cathodic Protection	CATPRO	No	N/A
Offsite Power	345kVAC Electrical	345kV	Yes	2.5
	19,000 Volt System	19kV	No	N/A
	Metering, Relaying and Regulation	MRR	Yes	2.5
	Switchyard Electrical Supervisory	SES	Yes	2.5
Plant Communications	Communications	COM	Yes	2.5
Plant Process Computers	Plant Process Computer System	PPCS	No	N/A
	Computers	COMP	No	N/A
Plant Security	Security	SEC	No	N/A
	Security Barrier Penetrations	SECPEN	No	N/A
	2400 Volt System	2.4kV	No	N/A
Radiation Monitoring	Radiation Monitoring	RM	Yes	2.5
Reactor Protection	Reactor Protection	RP	Yes	2.5
	ATWS Mitigation System Actuation Circuitry	AMSAC	Yes	2.5
Seismic and Meteorological Instrumentation	Meteorological	MET	No	N/A

2.3. SCOPING AND SCREENING RESULTS: MECHANICAL SYSTEMS

The scoping and screening results for mechanical systems consist of lists of components and component groups that require AMR, grouped and presented on a system basis. Brief descriptions of mechanical systems within the scope of SLR are provided as background information. Mechanical system intended functions are provided for in-scope systems. For each in-scope system, components or component groups requiring an AMR are provided. For the sections where the system description applies to the system on each unit, a statement is included indicating that the systems for Units 1 and 2 are essentially identical. The word “essentially” is utilized to clarify that there may be minor differences between the systems on each unit (e.g., valve numbering, locations of vents and drains, etc.), but these differences would not affect the information that follows.

The mechanical scoping and screening results are provided in four sections:

- Reactor coolant system (2.3.1)
- Engineered safety features (2.3.2)
- Auxiliary systems (2.3.3)
- Steam and power conversion systems (2.3.4)

2.3.1. Reactor Coolant System

Description

The reactor coolant system (RC) consists of the components designed to contain and support the nuclear fuel, contain the reactor coolant, and transfer the heat produced in the reactor to the steam and power conversion systems for the production of electricity. The RC for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units.

The RC consists of two loops connected in parallel to the reactor vessel, with each loop containing a steam generator and a reactor coolant pump (RCP). The system also includes a pressurizer, pressurizer relief tank (PRT), connecting piping, and instrumentation necessary for operational control. The RCPs circulate cold leg water through the reactor vessel where heat produced by the fission process is transferred to the coolant. The RC transfers the heat generated in the core to the steam generators, where steam is produced to drive the turbine generator. Cooling water is circulated at the flow rate and temperature consistent with achieving the reactor core thermal-hydraulic performance. The water also acts as a solvent for the neutron absorber used in chemical shim control, and as a neutron moderator and reflector. The RC provides a boundary for containing the coolant under operating temperature and pressure conditions. It also confines radioactive material and limits uncontrolled release of the reactor coolant to the secondary system and other parts of the plant to acceptable values. The inertia of the RCPs provides the necessary flow during a pump coast-down. The layout of the system assures natural circulation capability following a loss of forced flow to permit decay heat removal without overheating the core.

The two loops interface with various other systems, e.g., safety injection (SI), residual heat removal (RH), chemical and volume control system (CV), etc.

Boundary

The reactor coolant and connected piping boundaries are reflected on the SLR boundary drawings (SLRBD) listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort.

PBN Unit 1
SLR-541F091 Sheet 1
SLR-541F091 Sheet 2
SLR-541F091 Sheet 3
SLR-541F092
SLR-110E017 Sheet 1
SLR-110E018 Sheet 1
SLR-684J741 Sheet 3

PBN Unit 2:
SLR-541F445 Sheet 1
SLR-541F445 Sheet 2
SLR-541F445 Sheet 3
SLR-541F448
SLR-110E035 Sheet 1
SLR-110E029 Sheet 1
SLR-685J175 Sheet 3

PBN Common:
None

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Maintain reactor core assembly geometry.

(2) Introduce emergency negative reactivity to make the reactor subcritical.

(3) Provide reactor coolant pressure boundary.

(4) Provide emergency heat removal from the reactor coolant system using secondary heat removal capability.

(5) Provide heat removal from and/or pressure boundary of safety related heat exchangers.

(6) Provide primary containment boundary.

(7) Structurally support or house safety related components.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for fire protection.

(2) Perform a function that demonstrates compliance with the Commission's regulations for the EQ program.

(3) Perform a function that demonstrates compliance with the Commission's regulations for pressurized thermal shock.

(4) Perform a function that demonstrates compliance with the Commission's regulations for ATWS.

(5) Perform a function that demonstrates compliance with the Commission's regulations for station blackout.

UFSAR References

3.0
4.0
4.1
4.2
4.3

Components Subject to AMR

The RC is reviewed as the following subsystems. The fuel assemblies are periodically replaced based on burnup and are not subject to AMR.

- Reactor Vessel (2.3.1.1)
- Reactor Vessel Internals (2.3.1.2)
- Pressurizer (2.3.1.3)
- Reactor Coolant and Connected Piping (2.3.1.4)
- Steam Generators (2.3.1.5)

2.3.1.1. Reactor Vessel

Description

The PBN reactor vessels, as the principal component of the RC, contain the heat-generating core and associated supports, controls and instrumentation, and coolant circulating channels. Primary inlet and outlet nozzles provide for the exit of heated coolant and its return to the reactor vessel for recirculation through the core.

The PBN reactor vessels consist of a cylindrical shell with a hemispherical bottom head and a flanged and gasketed removable upper head. The Unit 1 reactor vessel shell is fabricated from a combination of longitudinally welded plate rings and an upper shell (nozzle belt) ring forging, joined by circumferential welds. The Unit 2 reactor vessel shell is fabricated from integral ring forgings joined by circumferential welds. The reactor vessels contain the core, core support structures, rod control clusters, thermal shield, and other parts directly associated with the core. Inlet and outlet nozzles are located at an elevation between the head flange and the core. The body of the reactor vessels is low-alloy carbon steel, and the inside surfaces in contact with coolant are clad with austenitic stainless steel to minimize corrosion. The reactor vessels are supported by steel pads integral with the coolant nozzles and lugs welded directly to the reactor vessel.

Subcomponents included for evaluation with the reactor vessels include the control rod drive mechanism (CRDM) head adapters and housings, bottom mounted instrument (BMI) penetrations and external guide tubing, head vent penetration, seal table and associated pressure boundary fittings, and the head closure bolting. The primary functions of the reactor vessels are to provide reactor coolant pressure boundary and fission product boundary, to support vessel internals and instrumentation, and direct the coolant flow.

Boundaries between the reactor vessels and associated systems and components are drawn at the reactor vessel interfaces. The evaluation boundaries for the reactor vessels extend to the primary inlet and outlet nozzle safe ends, safety injection nozzle safe ends and includes BMI penetrations and associated piping out to the seal table pressure boundary fittings. The reactor vessels interface with the following systems:

- Class 1 RC piping. Refer to Section 2.3.1.4 for the review of these components.
- The reactor vessel support structure is not screened as a part of the reactor vessels. Refer to Section 2.4.1 for the review of these structural components.

<u>UFSAR References</u>

3.0
4.0

<u>Components Subject to AMR</u>

Table 2.3.1-1 lists the reactor vessel component types that require AMR and their associated component intended functions.

Table 3.2.1-1 provides the result of the AMR

Table 2.3.1-1
Reactor Vessel Components Subject to Aging Management Review

Component Type[1]	Component Intended Function(s)
Bottom head	Pressure boundary Structural support
Bottom mounted instrumentation guide tubes	Pressure boundary Structural support
Closure flange and studs	Pressure boundary
Closure head dome and flange	Pressure boundary
Closure studs, nuts, washers	Mechanical closure
Core exit thermocouple nozzle assembly	Pressure boundary
Core support pads	Structural support
CRDM head adapter	Pressure boundary
CRDM latch housing	Pressure boundary
CRDM rod travel housing	Pressure boundary
Instrumentation port head adapter flange	Pressure boundary
Instrumentation tube safe ends	Pressure boundary Structural support
Instrumentation tubes	Pressure boundary Structural support
Nozzle support pads and external support brackets	Structural support
Primary inlet and outlet nozzle safe ends	Pressure boundary
Primary inlet and outlet nozzles	Pressure boundary Structural support
Reactor vessel components subject to fatigue	Pressure boundary
Refueling seal ledge	Structural support
Safety injection nozzle safe ends	Pressure boundary
Safety injection nozzles	Pressure boundary
Seal table	Structural support
Seal table fittings	Pressure boundary
Shells (intermediate, lower, upper)	Pressure boundary
Vent pipe	Pressure boundary
Vent pipe nozzle	Pressure boundary
Ventilation shroud support structure	Structural support
Vessel flange	Pressure boundary Structural support

Notes for Table 2.3.1-1

1. The CRDM thermal sleeves are addressed in Section 2.3.1.2 due to the interim guidance provided in MRP 2018-022 (Reference ML19081A057). PBN will continue to follow the developing industry aging management strategy for this component.

2.3.1.2. Reactor Vessel Internals

Description

The PBN reactor vessel internals consist of two basic assemblies:

- The upper internals assembly which is removed during each refueling operation to obtain access to the reactor core. The top of this assembly is clamped to a ledge below the vessel-head mating surface by the reactor vessel head. The core barrel alignment pins of the lower internals' assembly guides the bottom of the upper internals assembly.

- The lower internals assembly which can be removed, if desired following a complete core unload. This assembly is clamped at the same ledge below the vessel-head mating surface and closely guided at the bottom by radial/clevis assemblies that are part of the reactor vessel.

Subcomponents included for evaluation with the reactor vessel internals include all subcomponents inside the reactor vessel not welded as a permanent attachment to the inside or the reactor vessel. Those attachments are considered parts of the vessel. The primary functions of the reactor vessel internals are to provide structural support to the fuel assemblies, guide coolant through the reactor vessel, and guide and support any reactor core instrumentation or controls.

The reactor vessel internals evaluation boundary includes the control rod drive mechanism (CRDM) thermal sleeves. However, the CRDM head adapters which enclose the thermal sleeves are included in the evaluation boundary of the reactor vessels. Refer to Section 2.3.1.1 for the review of the CRDM head adapters.

UFSAR References

3.0
4.0

Components Subject to AMR

Table 2.3.1-2 lists the reactor vessel internals component types that require AMR and their associated component intended functions.

Table 3.1.2-2 provides the results of the AMR.

Table 2.3.1-2
Reactor Vessel Internals Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Alignment and interfacing components (clevis bearing Stellite wear surfaces)	Structural support
Alignment and interfacing components (clevis insert bolts)	Structural support
Alignment and interfacing components (clevis insert dowels)	Structural support
Alignment and interfacing components (upper core plate alignment pins)	Structural support
Baffle-former assembly (baffle plates, baffle edge bolts, former plates)	Structural support Flow distribution
Baffle-former assembly (baffle plates, former plates)	Structural support Flow distribution
Baffle-former assembly (baffle-edge bolts)	Structural support
Baffle-former assembly (baffle-former bolts)	Structural support
Bottom mounted instrumentation (column bodies)	Structural support
Bottom mounted instrumentation (flux thimble tubes)	Structural support Pressure boundary
Control rod guide tube assembly (guide cards)	Structural support
Control rod guide tube assembly (lower flange weld)	Structural support
Core barrel assembly (barrel former bolts)	Structural support
Core barrel assembly (core barrel flange)	Structural support Flow distribution
Core barrel assembly (core barrel outlet nozzle weld)	Structural support
Core barrel assembly (lower axial welds)	Structural support
Core barrel assembly (lower flange weld)	Structural support
Core barrel assembly (lower girth weld)	Structural support
Core barrel assembly (middle axial welds)	Structural support
Core barrel assembly (upper axial weld)	Structural support
Core barrel assembly (upper flange weld)	Structural support
Core barrel assembly (upper girth weld)	Structural support
Lower core plate (fuel alignment pins)	Structural support
Lower internals assembly (lower core plate)	Structural support Flow distribution
Lower internals assembly (lower support forging)	Structural support
Lower support assembly (lower support column bodies)	Structural support
Lower support assembly (lower support column bolts)	Structural support
No additional measures components[1]	Structural support Flow distribution
Radial support keys	Structural support
Reactor vessel internal components with a fatigue analysis	Structural support
Thermal shield assembly (thermal shield flexures)	Structural support
Upper core plate (fuel alignment pins)	Structural support
Upper internals assembly (upper core plate)	Structural support

Notes for Table 2.3.1-1

1. The CRDM thermal sleeves are grouped into this component type consistent with Section 3.1.2.2.10.2 and the RVI gap analysis in Appendix C.

2.3.1.3. Pressurizers

Description

The pressurizers for PBN Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units.

The pressurizer is part of the RC and is located inside containment. The pressurizer is used for RC pressure control and consists of the pressurizer vessel equipped with electric heaters, safety valves, relief valves, spray nozzle, interconnecting piping and instrumentation. During operation, the pressurizer contains saturated water and steam maintained at the desired saturation temperature and pressure by the use of electric heaters and the spray nozzle.

The pressurizer pressure control equipment is designed to absorb the reactor coolant volume surges and limit pressure variations during an initial transient period prior to an effective response by the control rod drive and indication and nuclear process instrumentation systems. The pressurizer performs the following functions:

- Maintains the required reactor coolant pressure (pressure boundary function) during steady-state operation and normal heatup and cooldown.
- Limits pressure changes, to an allowable range, that are caused by reactor coolant thermal expansion and contraction during normal plant load changes and transients.

The pressurizer scope is limited to the pressurizer pressure boundary up to and including the nozzles, nozzle safe ends, nozzle-to-safe end welds, and the support skirt and flange. Boundaries between the pressurizer and associated systems and components are typically drawn at the pressurizer interface. As such, the following systems/components are not considered as part of the pressurizer:

- Reactor coolant and connected piping and the attachment welds to the pressurizer nozzles/safe ends. Refer to Section 2.3.1.4 for the review of these components.
- Instrument piping / tubing, valve manifolds, and instruments. Refer to Section 2.3.1.4 for the review of these components.
- The pressurizer support skirt and flange, which are welded to the lower pressurizer head, are part of the pressurizer. However, the support attachment bolting is not part of the pressurizer. Refer to Section 2.4.1 for the review of these components.

UFSAR References

4.1
4.2

Components Subject to AMR

Table 2.3.1-3 lists the pressurizer component types that require AMR and their associated component intended functions

Table 3.2.1-3 provides the results of the AMR.

Table 2.3.1-3
Pressurizer Components Subject to Aging Management Review

Component Type[1]	Component Intended Function(s)
Heater well and sheath	Pressure boundary
Manway cover	Pressure boundary
Manway cover bolts	Pressure boundary
Pressurizer components subject to fatigue	Pressure boundary
Pressurizer components; heads, shell, nozzles	Pressure boundary
Safe ends, instrument nozzles, thermowells	Pressure boundary
Steel components	Pressure boundary Structural support
Support skirt and flange	Structural support
Thermal sleeves[2]	Insulate (thermal)

Notes for Table 2.3.1-3

1. In accordance with Section 2.3.1.4.2 of NUREG-1839, the pressurizer spray head does not perform any license renewal intended function. Support for not meeting the scoping and screening criteria of 10 CFR 54.21(a)(1) and (a)(3) are provided in the SER. In addition, the pressurizer spray head does not meet the criteria of 10 CFR 54.21(a)(2) as it does not provide structural support to reactor coolant pressure boundary components and does not have a leakage boundary function.

2. Thermal sleeves are not a part of the pressure boundary. However, thermal sleeves provide thermal shielding to minimize nozzle low-cycle thermal fatigue.

2.3.1.4. Reactor Coolant and Connected Piping

Description

The reactor coolant and connected piping for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units. The reactor coolant and connected piping can be divided distinctly into Class 1 and non-Class 1 components. Each of these divisions is discussed independently below.

Class 1 Piping and Components

The Class 1 reactor coolant and connected piping consists of the main reactor coolant system (RC) loops, and interconnecting piping from other systems, typically out to the second isolation valve off of the main RC loop. The RC consists of two heat transfer loops connected in parallel to the reactor pressure vessel (RPV). Each reactor coolant loop contains a reactor coolant pump (RCP) and steam generator (SG). In addition, the RC includes a pressurizer (connected to loop B hot leg through the pressurizer surge line), interconnecting piping and valves, and instrumentation necessary for protection and control.

The Class 1 reactor coolant and connected piping boundaries typically include branch piping and root isolation valves for various instruments. The Class 1 piping/component boundaries start with and include circumferential welds joining the piping to associated major RC component nozzles. The nozzle and nozzle safe ends are evaluated in the Section for the respective major component (e.g. the pressurizer nozzles and nozzle safe ends are evaluated with the pressurizer).

The Class 1 piping and components interface with a number of other systems that are connected to the Class 1 pressure boundary and, therefore, has many associated functions that support system functions for these other systems. These systems include the safety injection system (SI), residual heat removal system (RH), chemical and volume control system (CV), and plant sampling system.

The portions of the Class 1 piping and piping components subject to an AMR include the RC Class 1 piping, valves, and associated fittings; reactor coolant pump (RCP) casings; and Class 1 piping and valves of interfacing support systems that comprise the Class 1 boundary.

Non-Class 1 Piping and Components

The non-Class 1 reactor coolant and connected piping includes all safety Class 2, 3 and non-nuclear safety grade equipment used to functionally support the RC intended functions. Non-Class 1 RC components are used to sense and provide signals for reactor trip and the engineered safety features actuation system.

The portions of the non-Class 1 RC components subject to an AMR include all RC interconnected non-Class 1 piping, pressurizer safety valve and power operated relief valve (PORV) discharge piping to the pressurizer relief tank (PRT), and associated piping and valves to support the system intended functions.

UFSAR References

4.1
4.2
4.3

Components Subject to AMR

Table 2.3.1-4 lists the reactor coolant and connected piping component types that require AMR and their associated component intended functions

Table 3.1.2-4 provides the results of the AMR.

Table 2.3.1-4
Reactor Coolant and Connected Piping Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Bolting; piping and piping components	Mechanical closure
Bolting; pump and valve	Mechanical closure
Class 1 piping and piping components < 4" NPS	Pressure boundary
Flow indicators	Pressure boundary
Heat exchanger (RCP thermal barrier)[1]	Pressure boundary
Orifice	Pressure boundary Throttle
Piping and piping components	Pressure boundary Structural integrity (attached)
Pressurizer relief tank	Pressure boundary
Pump casing	Pressure boundary
Pump casing (thermal barrier flange and main flange)	Pressure boundary
Steel components	Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

Note for Table 2.3.1-4

1. The RCP thermal barrier heat exchangers that are in scope for the reactor coolant system and connected piping do not have a safety-related function of heat transfer per Section 2.3.1.1.2 of NUREG-1839. As such, pressure boundary is the only intended function requiring aging management.

2.3.1.5. Steam Generators

Description

PBN Units 1 and 2 began commercial operation with Westinghouse Model 44 steam generators. In 1983, PBN replaced the lower assemblies of the Model 44 steam generators in Unit 1 with Westinghouse Model 44F steam generator lower assemblies. This replacement was accomplished through a circumferential cut in the middle of the transition cone in matching locations on the original and replacement shells to allow a weld to be made away from the area of discontinuity where the original weld is located. The new bottom assembly and existing steam dome were joined by a closure weld performed in the field. In 1996, PBN installed the Westinghouse Model Δ47 steam generators in Unit 2. To allow passage through the hatch, the Unit 2 steam generators were cut in the middle of the transition cone and reassembled in containment with a transition cone closure weld performed in the field. In both cases, the replacements were required due to significant corrosion of the original Alloy 600 mill-annealed SG tubes and degradation of the carbon steel tube support plates of the original Westinghouse Model 44 steam generators. Note that the Unit 1 SGs contain Alloy 600 TT U-tubes while the Unit 2 SGs contain Alloy

690 TT U-tubes. On this basis, the following discussion applies to both units, with exceptions explicitly noted.

The steam generators (SG) form the boundary between the radioactive reactor coolant system (RC) and the non-radioactive secondary systems. There are two steam generators installed in each containment, one in each reactor coolant system loop. The SG is a vertical shell and tube heat exchanger, where heat transferred from a single-phase fluid at high temperature and pressure (reactor coolant) on the tube side is used to generate a two-phase (steam-water) mixture at a lower temperature and pressure on the shell side. The reactor coolant flows through the primary side, or inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator.

The steam-water mixture is generated on the secondary, or shell side of the steam generator. Feedwater from the feedwater and condensate system enters the steam generator through the feed ring, mixes with recirculated fluid, flows downward around the tube bundle inner shroud, then enters the tube bundle area where heat is transferred from the RC. The mixture is heated and flows upward through the tube bundle by natural circulation, changing into a steam-water mixture. As the steam-water mixture leaves the tube bundle, it enters the moisture separator section where water is extracted from the steam in two stages. Essentially dry steam exits the moisture separation section and exits the steam generator through the steam nozzle to the main and auxiliary steam system.

The steam nozzle contains a flow limiting device which operates on the venturi principle. The flow limiting device is intended to limit steam flow in the event of a postulated steam line break accident.

Boundaries between the steam generators and associated systems and components are drawn at the steam generator interface. The steam generators interface with the following systems:

- Reactor coolant and connected piping. Refer to Section 2.3.1.4 for the review of these components.
- Feedwater and condensate. Refer to Section 2.3.4.2 for the review of these components.
- Main and auxiliary steam. Refer to Section 2.3.4.1 for the review of these components.
- The support attachment bolting, and associated structures are not part of the steam generators screening and aging management review. Refer to Section 2.4.1 for the review of these components.

The primary functions of the steam generators are pressure boundary, both primary and secondary side; heat removal from the reactor coolant system; and structural support.

UFSAR References

4.0

Components Subject to AMR

Table 2.3.1-5 lists the steam generator component types that require AMR and their associated component intended functions

Table 3.2.1-5 provides the results of the AMR.

Table 2.3.1-5
Steam Generator Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anti-vibration bars	Structural support
Blowdown piping nozzles and secondary side shell penetrations	Pressure boundary
Channel head drain coupling and Alloy 152 weld filler (U1)	Pressure boundary
Channel head with primary nozzles	Pressure boundary
Divider plate	Direct flow
Feedwater nozzle	Pressure boundary
Feedwater feedring and support structure	Structural integrity (attached)
Feedwater J-nozzles	Structural integrity (attached)
Lower shell	Pressure boundary
Moisture separators	Direct flow
Primary manway bolting	Pressure boundary
Primary manway cover	Pressure boundary
Primary nozzle safe end Alloy 82/182 welds (U2)	Pressure boundary
Primary nozzle safe ends	Pressure boundary
Primary side Alloy 690 vent nozzles (U2)	Pressure boundary
Secondary closure bolting (excluding U1 inspection port)	Pressure boundary
Secondary closures	Pressure boundary
Seismic lugs	Structural support
Steam flow limiter	Throttle
Steam generator components with fatigue analysis	Pressure boundary
Steam outlet nozzle	Pressure boundary
Support pads	Structural support
Transition cone	Pressure boundary
Transition cone welds (new welds)	Pressure boundary
Transition cone welds (U1 original welds)	Pressure boundary
Tube bundle wrapper and wrapper support system	Direct flow Structural support
Tube plugs	Pressure boundary
Tube support plates	Structural support
Tubesheet	Pressure boundary
Tube-to-tubesheet weld (U2)	Pressure boundary
Upper and lower shell, elliptical head and transition cone	Pressure boundary
U-tubes	Pressure boundary Heat transfer

2.3.2. Engineered Safety Features

2.3.2.1. Safety Injection

Description

The safety injection (SI) system supports the reactor coolant system (RC) inventory and reactivity control during accident and post-accident conditions by automatically delivering borated water to the reactor vessel for cooling under high and low reactor coolant pressure conditions. Additionally, the safety injection system serves to insert negative reactivity into the reactor core in the form of borated water during an uncontrolled plant cooldown following a steam line break or an accidental steam release.

The SI system for each PBN unit consists of the following principal components: two passive accumulators (including the nitrogen supply boundary to these tanks), refueling water storage tank (RWST), two safety injection pumps (high pressure injection), and the associated piping and valves to support the system intended functions. The residual heat removal pumps perform the low pressure safety injection function to support the SI system. (The residual heat removal components are addressed in the residual heat removal system, Section 2.3.2.3.) The accumulators are passive devices that discharge into the cold leg of each loop. During MODES 1 and 2, the RWST is aligned to the suction of the SI pumps, containment spray pumps, and residual heat removal pumps. After the injection phase, spilled and sprayed water collects in the containment sump. The RH/SI systems can then be aligned to take suction from the containment sump, cool the fluid, and supply cooled water to the SI system and the containment spray system for re-injection or spray.

Class 1 boundary components that carry a SI equipment designation are addressed in the Class 1 Piping/Components system (Section 2.3.1). The safety injection system is a standby system during normal plant operation.

Boundary

The SLR boundaries for the SI system are reflected on the SLR boundary drawings listed below. The significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort include the addition of piping and valves to provide an alternative nitrogen supply from the safety injection accumulators to the PORVs. This modification is part of the implementation of NFPA-805 to provide additional flexibility of supplying motive gas to the PORVs as developed in the Fire Probabilistic Risk Assessment (PRA) model. The Unit 1 piping and associated valves 1-905A and 1-905 are shown on boundary drawing SLR-110E017, Sheet 1 (coordinates H-3 and G-3) and the Unit 2 piping and associated valves 2-905A and 2-905 are shown on boundary drawing SLR-110E035, Sheet 1 (coordinates H-3 and G-3).

The original PBN license renewal application did not include a lubricating oil environment for the SI system. However, review of the design documents for the safety injection pumps indicates there is piping and a sight glass attached to the SI pump bearing oil reservoir. The piping and sight glass are included in the scope of

SLR and have a pressure boundary intended function to ensure lubrication of the pump bearings is maintained. Therefore, a lubricating oil environment is added for the piping and sight glass connected to the SI pumps

The Unit 1 piping and components downstream of valves 1-826B and 1-826C on boundary drawing SLR-110E017-2, Sheet 2 (coordinate H-6) and the Unit 2 piping and components downstream of valves 2-826B and 2-826C on boundary drawing SLR-110E035, Sheet 2 (coordinate G-6) perform a 10 CFR 54.4(a)(2) leakage boundary (spatial) intended function. In addition, the Unit 1 SI piping, valves, and flow indicator 1-FIT-659 between valves 1-829A (coordinate F-9), 1-829B (coordinate F-9), and 1-829C (coordinate G-7) on boundary drawing SLR-110E017, Sheet 2 performs a 10 CFR 54.4a(2) leakage boundary (spatial) intended function. Similarly, the Unit 2 piping, valves, and flow indicator 2-FIT-659 between valves 2-829A (coordinate F-9), 2-829B (coordinate E-9), and 2-829C (coordinate H-7) on boundary drawing SLR-110E035, Sheet 2 performs a 10CFR54.4(a)(2) leakage boundary (spatial) intended function.

The safety injection boundaries with the reactor coolant system include valves 1-866A, 1-866B, 1-867A, 1-867B, 1-853C, and 1-853D on SLR-110E017 Sheet 1 and valves 2-866A, 2-866B, 2-867A, 2-867B, 2-853C, and 2-853D on SLR-110E035 Sheet 1; with the chemical and volume control system at valves 1-827A and 1-827B on SLR-110E017 Sheet 2 along with 2-827A and 2-827B on SLR-110E035 Sheet 2; with the residual heat removal system at valves 1-854A and 1-854B SLR-110E017 Sheet 2 along with 2-854A and 2-854B on SLR-110E035 Sheet 2; and with containment spray at valves 1-870A and 1-870B on SLR-110E117 Sheet 2 along with 2-870A and 2-870B on SLR-110E035 Sheet 2.

<u>PBN Unit 1:</u>
SLR-110E017 Sheet 1
SLR-110E017 Sheet 2

<u>PBN Unit 2:</u>
SLR-110E035 Sheet 1
SLR-110E035 Sheet 2

<u>PBN Common:</u>
None

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Increases the boron concentration in the reactor coolant system during the injection phase of safety injection to ensure adequate reactor shutdown margin in the event of a secondary pipe break.

(2) The safety injection system provides sufficient boron to maintain an adequate post-LOCA sump mean boron concentration to ensure shutdown of the core with all control rods out.

(3) Delivers borated water to the reactor coolant system, as necessary, to compensate for Xenon decay to maintain hot shutdown margin.

(4) Provide reactor coolant pressure boundary.

(5) Delivers borated cooling water to the reactor coolant system during the injection phase of safety injection to support core cooling.

(6) Provides heat removal from and pressure boundary of safety related heat exchangers.

(7) Provide isolation of lines penetrating containment to maintain the containment pressure boundary.

(8) Provides the liquid capacity in the form of the RWST for the containment spray system to provide emergency heat removal from primary containment and provide containment pressure control.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for fire protection, SBO, and the EQ program.

<u>UFSAR References</u>

6.2
14.3

<u>Components Subject to AMR</u>

Table 2.3.2-1 lists the safety injection system component types that require AMR and their associated component intended functions

Table 3.2.2-1 provides the results of the AMR.

Table 2.3.2-1
Safety Injection System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator	Pressure boundary
Bolting	Mechanical closure
Flow element	Pressure boundary
Heat exchanger (seal water)	Heat transfer Pressure boundary
Instrument	Leakage boundary (spatial) Pressure boundary
Level element	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pump casing	Pressure boundary
Steel components adversely affected by boric acid leakage	Pressure boundary
Tank (refueling water storage)	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.2.2. Containment Spray

Description

The containment spray system is designed to remove sufficient heat from the containment atmosphere following an accident condition to maintain the containment pressure below design limits. The containment spray system, in conjunction with the sodium hydroxide (NaOH) tank, is also capable of reducing the radioactive elemental iodine and particulates in the containment atmosphere such that the offsite radiation exposure resulting from a LOCA is within the guidelines established by 10 CFR 50.67. The addition of NaOH is also credited to reduce the pH levels within the containment sump in order to prevent chloride stress corrosion cracking (SCC) and iodine re-evolution.

The containment spray system for each PBN unit consists of the following principal components: two spray pumps, one NaOH tank, two spray headers, two eductors, spray nozzles, and the associated piping and valves to support the system intended functions. The system initially takes suction from the refueling water storage tank (RWST). When a low level is reached in the RWST, the spray pump suction is fed from the discharge of the residual heat removal pumps (using sump recirculation) if continued spray is required.

During the period of time that the spray pumps draw from the RWST, spray additive will be added to the refueling water in each train by using a liquid eductor enabled by the spray pump discharge. The result will be a solution suitable for the removal of radionuclides in the air and prevention of iodine re-evolution in the containment sump.

Additionally, a combination of one spray pump and two containment cooling fans will provide sufficient heat removal capability to maintain the LOCA post-accident containment pressure below the design value of 60 psig at 286°F (100 percent R.H.), assuming that the core residual heat is released to the containment as steam.

The portions of the containment spray system containing components subject to an AMR extend from the pump suction supplies from the RWST or the RH pump discharge, to the spray headers and include the NaOH tank, eductors, spray pumps and the test return lines.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort. The Unit 1 containment spray system interfaces with the SI system at valves 1-870A, 1-870B, and 1-862K and with the RHR system at valves 1-817A and 1-817B on drawing SLR 110E017, Sheet 3. The Unit 2 containment spray system interfaces with the SI system at valves 2-870A, 2-870B, and 2-862K and with the RHR system at valves 2 817A and 2-817B on drawing SLR-110E035, Sheet 3.

The containment spray pump full flow test line between normally closed Unit 1 valves 1 862J, 1-862G, 1-862H and flow indicator 1FIT-661 (SLR-110E017, Sheet 3 coordinates G-8, D-8, and E-9) and normally closed Unit 2 valves 2-862J, 2 862G, 2-862H, and flow indicator 2-FIT-661 (SLR-110E035, Sheet 3 coordinates F-8, D-8, and E-9) perform an a(2) leakage boundary (spatial) intended function.

PBN Unit 1:
SLR-110E017 Sheet 3

PBN Unit 2:
SLR-110E035 Sheet 3

PBN Common:
None

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provides heat removal from and/or pressure boundary of safety related heat exchangers.

(2) Provide isolation of lines penetrating containment to maintain the containment pressure boundary.

(3) Provides emergency heat removal from primary containment and provides containment pressure control.

(4) Provides emergency removal of radioactive material from the primary containment atmosphere

(5) Transfers sodium hydroxide from the spray additive tank to the containment sump.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for fire protection and the EQ program.

UFSAR References
6.4
9.1.1
Appendix C.1

Components Subject to AMR

Table 2.3.2-2 lists the containment spray system component types that require AMR and their associated component intended functions

Table 3.2.2-2 provides the results of the AMR.

Table 2.3.2-2
Containment Spray System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Eductor	Pressure boundary
Flow element	Leakage boundary (spatial) Pressure boundary
Heat exchanger (containment spray pump seal water)	Heat transfer Pressure boundary
Instrument	Leakage boundary (spatial) Pressure boundary
Nozzle	Pressure boundary Spray
Orifice	Pressure boundary Throttle
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary
Steel components adversely affected by boric acid leakage	Pressure boundary
Tank (spray additive)	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.2.3. Residual Heat Removal

Description

The residual heat removal system is a dual purpose system. During power operation, the system is in standby service and is aligned to perform its emergency low head safety injection function. During a plant shutdown to cold shutdown conditions, the RHR pumps and heat exchangers perform the residual heat removal functions for the reactor.

During a LOCA, the residual heat removal system pumps and valves automatically deliver borated water to the reactor vessel for cooling under low reactor coolant system (RC) pressure conditions. The refueling water storage tank (RWST) is aligned to the suction of the RH pumps. After the injection phase, the RH pumps will take suction from the containment sump, circulate the spilled coolant through the RH heat exchangers, and return the coolant to the reactor via the reactor vessel nozzles. If depressurization of the RC proceeds slowly, the safety injection pumps are aligned to take suction from the RH pump discharge and inject water into the RC cold legs. The RH pumps and heat exchangers, in conjunction with the containment spray system, may also be used during the recirculation phase to supply water from the containment sump for use in heat removal and pressure control of the containment atmosphere.

For normal plant cooldown and shutdown, the RH system is designed to transfer the fission product decay heat and other residual heat from the reactor core to the component cooling water system. Decay heat cooling is initiated by aligning the RH pumps to take suction from RC loop A hot leg and discharge through the RH heat exchangers to the loop B cold leg.

The RH system for each PBN unit consists of the following principal components: two RH pumps, two heat exchangers, and the associated piping and valves to support the system intended functions. There are Class 1 boundary components within the high temperature RC envelope that carry a RH equipment designation. These components are addressed in the reactor coolant and connected piping system (2.3.1.1). The residual heat removal system is a standby system during normal plant operation.

The portions of the residual heat removal system containing components subject to an AMR extend from the RH pump suction supply from the RWST or the containment sump, system inter-connections to the RCS, and the safety injection and containment spray pump suction supply (for recirculation operation). Also, each PBN unit has two containment recirculation sump outlet lines that include one remote hydraulically-operated valve located inside containment (valves 1-850A and 1-850B for Unit 1 and 2-850A and 2-850B for Unit 2). Operation of the hydraulic system is required to open the sump outlet valves. Therefore, the hydraulic system pump, tank, piping and valves are in the scope of SLR and are also subject to an AMR.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort.

The Unit 1 RHR piping between valves 1-175C, 1-V14A, 1-V14, 1-D13 and the associated two continuation flags on drawing SLR-110E018, Sheet 1 (coordinates E-6 and F-6) performs a 10 CFR 54.4(a)(2) leakage boundary (spatial) intended function. Similarly, the Unit 2 RHR piping between valves 2-175C, 2-V14A, 2-D13 and the associated two continuation flags on drawing SLR-110E029, Sheet 1 (coordinates E-6 and F-6) also performs a 10 CFR 54.4(a)(2) leakage boundary (spatial) intended function.

PBN Unit 1:
SLR-110E017 Sheet 1
SLR-110E018 Sheet 1

PBN Unit 2:
SLR-110E029 Sheet 1
SLR-110E035 Sheet 1

PBN Common:
None

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide reactor coolant pressure boundary

(2) Remove residual heat from the reactor coolant system

(3) Provide emergency core coolant directly to the core

(4) Provide heat removal from and/or pressure boundary of safety related heat exchangers

(5) Provide isolation of lines penetrating containment to maintain the containment pressure boundary.

(6) Provide emergency heat removal from primary containment and provide containment pressure control

(7) Minimize release of radioactive effluents to the environment during transient or accident environment as tested per the LRPM program and TS 5.5.2 and TRM 4.2.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety functions

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for fire protection and the EQ program.

UFSAR References

5.2
6.2
6.4.2
9.1.1
9.2

Components Subject to AMR

Table 2.3.2-3 lists the residual heat removal system component types that require AMR and their associated component intended functions

Table 3.2.2-3 provides the results of the AMR.

Table 2.3.2-3
Residual Heat Removal System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Flow element	Leakage boundary (spatial) Pressure boundary
Heat exchanger (RHR)	Heat transfer Pressure boundary
Heat exchanger (seal water)	Heat transfer Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pump casing	Pressure boundary
Steel components adversely affected by boric acid leakage	Pressure boundary
Sump screen	Filter
Tank (hydraulic operator)	Pressure boundary
Thermowell	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.2.4. Containment Isolation Components

Description

The containment isolation components system was created as a virtual system for those systems whose only SR function is to provide a containment isolation function.

Each system whose piping penetrates the containment leakage-limiting boundary is designed to maintain or establish isolation of the containment from the outside environment under any accident condition for which isolation is required. Piping penetrating the containment is designed for pressures at least equal to the containment design pressure. Containment isolation boundaries are provided as necessary in lines penetrating the containment to ensure that no unrestricted release of radioactivity can occur. Valving or loop seals for penetrations are used to maintain containment integrity.

Components addressed within the containment isolation components system include containment penetration isolation valves, flanges, seals, caps, and the associated piping and valves to support the system intended functions. The system includes demineralized water penetrations, radiation monitoring system containment air sample penetrations, spare containment penetrations, and tubing and valves that support air-lock testing.

The portions of the containment isolation components system containing components subject to an AMR extend between the penetration isolation valves and include penetration test valves, flanges, and piping for demineralized water sub-system penetrations, radiation monitoring system containment air sample penetrations, spare containment penetrations, and associated airlock support equipment. For boundary drawing SLR-PBM-231, Sheet 2, the valves and piping associated with penetration P-12A are contained within the evaluation boundary for the containment isolation components system. The valves and piping associated with the containment hatches and the RE-211 and RE-212 supply and return lines on boundary drawing SLR-M-224 are contained within the evaluation boundary for the containment isolation components system.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort.

PBN Unit 1:
SLR-M-215 Sheet 2

PBN Unit 2:
SLR-M-2215 Sheet 2

PBN Common:
SLR-PBM-231 Sheet 2
SLR-M-224

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provides isolation of lines penetrating containment to maintain the containment pressure boundary.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for the EQ program.

UFSAR References

5.2

Components Subject to AMR

Table 2.3.2-4 lists the containment isolation components system component types that require AMR and their associated component intended functions

Table 3.2.2-4 provides the results of the AMR.

Table 2.3.2-4
Containment Isolation Components System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Steel components adversely affected by boric acid leakage	Pressure boundary
Valve body	Pressure boundary

2.3.3. Auxiliary Systems

2.3.3.1. Chemical and Volume Control

Description

The chemical and volume control system (CV) described in this section includes the boron recycle (BS) and reactor makeup water (RMW) systems. The CV (a) adjusts the concentration of chemical neutron absorber for chemical reactivity control, (b) maintains the proper water inventory in the reactor coolant system (RC), (c) provides the required seal water flow for the reactor coolant pump shaft seals, (d) maintains the desired concentration of corrosion controlling chemicals in the reactor coolant, (e) keeps the reactor coolant activity to within the design levels and (f) provides for RC degasification. The system is also used to fill, drain, and hydrostatically test the reactor coolant system.

The CV for each PBN unit consists of the following principal components: volume control tank (VCT), three positive displacement charging pumps, regenerative heat exchanger, non-regenerative heat exchanger, excess letdown heat exchanger, seal water heat exchanger, demineralizers, and the associated piping and valves to support the system functions.

The charging portion of the system consists of the three charging pumps taking suction from either the VCT or the RWST and pumping forward to the RC via either the RCP seal injection lines or through the regenerative heat exchanger into the A loop cold leg. The letdown portion of the system consists of the regenerative heat exchanger and the non-regenerative heat exchanger which cool the RCS letdown. Letdown flow is controlled via three parallel orifices that also serve to reduce system pressure. Letdown flow is then routed through filters and demineralizers to clean up the water, which is eventually returned to the VCT. An alternate means of letdown is through the excess letdown heat exchanger. RCP seal return flow passes through a containment isolation valve and is then cooled by the seal water heat exchanger.

There are Class 1 pressure boundary components that carry a CV equipment designation. These components are addressed in the Class 1 Piping/Components System. The chemical and volume control system is in continuous service during normal plant operation.

Boundary

The CV boundaries are reflected on the SLR boundary drawings listed below. There are differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort include abandonment of the boric acid evaporator system.

The in-scope portion of the CV includes the safety-related components that perform a containment isolation function. These components are associated with containment penetrations P-10, P-11, P-26, P-29A, P-29B and P-32C shown on Unit 1 boundary drawings SLR-684J741, Sheets 2 and 3 and Unit 2 boundary drawings SLR-685J175, Sheets 2 and 3. Isolation of these containment penetrations is also credited in the PBN station blackout (SBO) analysis.

The CV is also credited for providing RC inventory control during NFPA-805 fire scenarios. The CV components that perform this function are included on Unit 1 boundary drawings SLR-684J741, Sheets 2 and 3 and Unit 2 boundary drawings SLR-685J175, Sheets 2 and 3. The RC makeup flowpath is established by isolation of the VCT and aligning the charging pump suction to the RWST. The charging pumps deliver borated water though penetrations P-29A and P-29B to the RC via the RCP seals. The normal charging (P-26) and auxiliary charging (P-32C) flowpaths to the RC are isolated. RC inventory is also maintained by isolating the normal letdown (P-10) and excess letdown (P-11). The shaded CV components outside of these flowpaths on Unit 1 boundary drawings SLR-684J741, Sheets 2 and 3 and Unit 2 boundary drawings SLR-685J175, Sheets 2 and 3 are in scope as they perform a 10 CFR 54.4(a)(2) leakage boundary (spatial) intended function.

The flowpath from the non-safety related reactor makeup water tank (RMWT) is included in the scope of SLR as it provides a 10 CFR 54.4(a)(2) emergency backup source of water to the component cooling water system surge tanks to accommodate leakage from the component cooling water loops. This flowpath is shown on boundary drawing SLR-PBM-231, Sheet 1, coordinates C-6, C-5, C-4, C-3, D-3, and D-1. The shaded components outside of this flowpath on boundary drawing SLR-PBM-231, Sheet 1 are in scope as they perform a 10 CFR 54.4(a)(2) leakage boundary (spatial) intended function.

The CV components shaded on the remaining CV boundary drawings (SLR-541F094, SLR-PBM-226, SLR-684J741 Sheet 1, SLR-684J961 Sheet A, SLR-684J961 Sheet B, SLR-541F450 Sheet 2, and SLR-685J175 Sheet 1) are in scope as they perform a 10 CFR 54.4(a)(2) leakage boundary (spatial) intended function. Note that several in-line components within the shaded boundaries on these drawings are not shaded. These components include the evaporator feed ion exchanger, filter, and boric acid gas stripper package on boundary drawing SLR-541F450 Sheet 2, the boron recycle demineralizers, filter, and boric acid gas stripper package on boundary drawing SLR-684J961 Sheet A, holdup tanks A, B, and C and concentrates holding tank on boundary drawing SLR-684J961 Sheet B, and prefilters on boundary drawing SLR-PBM-226. These components are excluded from the scope of 10 CFR 54.4(a)(2) consistent with Exceptions 2 and 5 described in Section 2.1.4.2.3.

CV boundary drawings indicates that the tank 2-T58 is abandoned in place. This tank is not in-scope for SLR as the tank has been physically disconnected from the system in accordance with the PBN abandoned equipment procedures (Section 2.1.4.2.4).

PBN Unit 1:
SLR-684J741 Sheet 1
SLR-684J741 Sheet 2
SLR-684J741 Sheet 3
SLR-684J961 Sheet A
SLR-684J961 Sheet B

PBN Unit 2:
SLR-541F450 Sheet 2
SLR-685J175 Sheet 1
SLR-685J175 Sheet 2
SLR-685J175 Sheet 3

PBN Common:
SLR-541F094
SLR-PBM-226
SLR-PBM-231 Sheet 1

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) CV piping and components interfacing with pressure boundaries for the:

(a) reactor coolant system,

(b) component cooling water system,

(c) safety injection system (refueling water storage tank), and

(d) residual heat removal system shall maintain the pressure boundary integrity to support the safety function of these systems.

(2) CV containment isolation valves and portions of the CV that function as a closed system outside containment shall maintain containment integrity following accidents that require containment isolation.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

(2) Provide an emergency source of makeup water to the component cooling water system via the reactor makeup water tank.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for fire protection, the EQ Program and for SBO.

UFSAR References

5.2
9.1
9.3
14.1.4

Components Subject to AMR

Table 2.3.3-1 lists the chemical volume and control system component types that require an AMR and their associated component intended functions.

Table 3.3.2-1 provides the results of the AMR.

Table 2.3.3-1
Chemical Volume and Control System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Flow element	Leakage boundary (spatial) Pressure boundary
Heat exchanger (excess letdown)(1)	Pressure boundary
Heat exchanger (non-regenerative)(1)	Pressure boundary
Heat exchanger (regenerative)(1)	Pressure boundary
Heat exchanger (seal water)(1)	Pressure boundary
Instrument	Leakage boundary (spatial) Pressure boundary
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pump casing	Leakage boundary (spatial) Pressure boundary
Steel components adversely affected by boric acid leakage	Leakage boundary (spatial) Pressure boundary

Table 2.3.3-1
Chemical Volume and Control System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Strainer	Filter Leakage boundary (spatial) Pressure boundary
Tank (batching)	Leakage boundary (spatial)
Tank (boric acid storage)	Leakage boundary (spatial)
Tank (chemical mixing)	Leakage boundary (spatial)
Tank (evaporator condensate demineralizer)	Leakage boundary (spatial)
Tank (monitor)	Leakage boundary (spatial)
Tank (reactor makeup water)	Pressure boundary
Tank (volume control)	Leakage boundary (spatial)
Thermowell	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

Notes for Table 2.3.3-1

1. In accordance with Section 2.3.1.1.2 of NUREG-1839, the CV system heat exchangers did not have a heat transfer component intended function for license renewal. Review of current plant documentation concludes these heat exchangers do not have a heat transfer component intended function for SLR.

2.3.3.2. Component Cooling Water

Description

The component cooling water (CC) system consists of four pumps, four heat exchangers, two surge tanks, and the piping, valves and instrumentation to provide heat removal capabilities to support the operation of both PBN Units and various equipment. The CC system precludes leakage of the containment atmosphere into the CC system piping to limit the release of radioactive materials and removes residual and sensible heat from:

a) the RC system via the RH heat exchangers during the recirculation phase of SI to support long-term core cooling;

b) the RH heat exchangers to mitigate the consequences of a postulated MSLB or steam generator tube rupture (SGTR) accident;

c) the RH, SI, and CS pump seal coolers to maintain the integrity of the pump seals; and

d) the RCP thermal barrier cooling coils to ensure RC integrity.

The loop in each unit consists of two pumps, two heat exchangers, a surge tank a supply header and a return header. The CC heat exchangers are cooled by the service water system (SW). During normal full power operation, one component cooling pump and one component cooling heat exchanger accommodate the heat removal loads and the standby pump and the shared heat exchangers provide 100% backup. Two pumps and two heat exchangers are used to remove the residual and sensible heat during plant shutdown. If one of the pumps or two of the heat exchangers are not operable, safe shutdown of the plant is not affected; however, the time for cooldown is extended.

The CC surge tank accommodates expansion, contraction and in-leakage of water. A radiation monitor in the CC system return header closes the surge tank vent valve (if open) in the unlikely event that the radiation level reaches a preset level above the normal background. Potassium chromate is added to the CC loops to prevent corrosion. The CC is in continuous service during normal plant operation.

Boundary

The in-scope portion of the CC system is a) the safety-related components, up to and including the valves that can be remotely isolated from the non-safety related portions of the CC system, and b) non-safety-related CC components contained within the PAB and façade, as shown on boundary drawing SLR-PBM-230 (coordinates B-3, B-4, H-3, and H-4), for 10 CFR 54.4(a)(2) considerations.

The in-scope components in the CC system includes pumps, heat exchangers (both CC heat exchangers and sample coolers), tanks, piping (including the piping to the CC pump oiler), thermowells, instruments (radiation monitors), flow elements, and valves as well as the bolting associated with these components. The CC system interfaces with the -

- RC pump thermal barrier cooling coils (Section 2.3.1.4);
- SI pump seal water heat exchangers (Section 2.3.2.1);
- Containment spray (CS) pump seal water heat exchangers (Section 2.3.2.2);
- RH heat exchangers and pump seal water heat exchangers (Section 2.3.2.3);
- Excess letdown, non-regenerative, and seal water heat exchangers as well as the reactor makeup water tank (RMWT), emergency surge tank backup, in the chemical and volume control system (CV) (Section 2.3.3.1);
- Waste gas compressor heat exchanger in the waste disposal system (Section 2.3.3.4);
- Service water piping, at the component cooling heat exchangers, (Section 2.3.3.5); and
- Plant sampling system piping, at the primary and steam generator blowdown sampling heat exchangers, (Section 2.3.3.14).

The CC system boundaries are reflected on the SLR boundary drawings listed below. There are differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort due to abandonment of the blowdown evaporator.

PBN Unit 1:
SLR-110E018 Sheet 1
SLR-110E018 Sheet 2
SLR-110E018 Sheet 3

PBN Unit 2:
SLR-110E029 Sheet 1
SLR-110E029 Sheet 2
SLR-110E029 Sheet 3

PBN Common:
SLR-PBM-230

In addition, the non-safety-related piping and piping components associated with waste evaporator distillate cooler and concentrator are attached to safety-related components. As such, though not highlighted on boundary drawings SLR-110E018 Sheet 3 and SLR-110E029 Sheet 3, the piping and piping components are included in the scope of SLR with a structural integrity (attached) function.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Remove residual and sensible heat from the reactor coolant system, via the residual heat removal (RH) heat exchangers during the recirculation phase of safety injection (SI) to support long-term core cooling.

(2) Remove heat from the RH heat exchangers to terminate the steam releases associated with the license basis dose analyses for the postulated rupture of a steam pipe (main steam line break (MSLB)), steam generator tube rupture (SGTR), and reactor cooling pump locked rotor accidents.

(3) Remove heat from the RH, SI, and containment spray pump seal coolers to maintain the integrity of the pump seals.

(4) Preclude leakage of the containment atmosphere into the CC piping to limit the release of radioactive materials.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection, the EQ Program, and SBO.

UFSAR References

6.2.2
9.1
14.1.8
14.2.4
14.2.5

Components Subject to AMR

Table 2.3.3-2 lists the component cooling water system component types that require an AMR and their associated component intended functions.

Table 3.3.2-2 provides the results of the AMR.

Table 2.3.3-2
Component Cooling Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Flow element	Leakage boundary (spatial) Pressure boundary
Heat exchanger (component cooling)	Heat transfer Pressure boundary
Heat exchanger (pressurizer liquid sample)	Pressure boundary
Heat exchanger (pressurizer steam sample)	Pressure boundary
Heat exchanger (reactor coolant hot leg sample)	Pressure boundary
Heat exchanger (steam generator blowdown sample)	Pressure boundary
Instrument	Pressure boundary
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing	Leakage boundary (spatial) Pressure boundary
Steel components adversely affected by boric acid leakage	Leakage boundary (spatial) Pressure boundary
Tank (surge)	Pressure boundary
Thermowell	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.3. Spent Fuel Cooling

Description

The spent fuel cooling (SF) system is common to PBN Units 1 and 2. This system removes decay heat produced by irradiated fuel assemblies stored in the spent fuel pool (SFP). The SF system consists of two separate trains, with a common suction and return header, each having an identical heat exchanger and pump, and the associated piping and valves to support the system intended functions. The fuel transfer tube isolation valves are also included in the scope of the spent fuel cooling system.

Water from the pool is pumped through one or both heat exchangers for cooling and returned to the pool. When purification is required, a portion of the flow is diverted through the interconnecting SF purification sub-system. When in this configuration, this portion of the SF becomes part of the SF pressure boundary. As a result, it is being conservatively included in the scope of subsequent license renewal (SLR) for functional support of the SF pressure boundary per 10 CFR 54.4(a)(2). This is a change from the original 10 CFR 54.4(a)(2) scoping for PBN. Service water (SW) is provided to the heat exchangers for removal of decay heat, although SW can be interrupted during accident conditions. The SF system is normally in continuous service during normal plant operation.

The SF system piping is arranged such that failure of any piping does not drain the SFP. To protect against the possibility of a complete loss of water in the SFP, the suction line terminates near the top of the pool. The SF system cooling water return line, which terminates lower in the pool, contains a siphon break line near the normal SF water level such that the pool water cannot be siphoned. In the event of complete failure of the cooling system for a long period of time, the fuel pool water inventory can be maintained with fire suppression system water.

The portion of the system in scope for a leakage boundary (spatial) intended function includes the piping and valves to/from the skimmer-pump system.

Boundary

The SF system boundaries are reflected on the SLR boundary drawing listed below. There are some differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort as summarized above for the SF purification loop.

PBN Unit 1:
None

PBN Unit 2:
None

PBN Common:
SLR-110E018 Sheet 4

The subsequent license renewal boundaries of the spent fuel cooling system shown on the boundary drawing include components that form the system boundaries with the safety injection system, service water system, chemical and volume control system, waste disposal system, and the fire water system. These interfaces are as follows:

- Safety Injection - Supplies normal makeup water from RWST to spent fuel pool.
- Service Water - Supplies cooling water to spent fuel pool heat exchangers

- Chemical Volume and Control System - Provides makeup and borated water supply.
- Waste Disposal - Cleanup and disposal of waste liquids.
- Fire Water - Maintain spent fuel pool inventory if cooling system is unavailable for long periods of time.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Remove decay heat produced by irradiated fuel assemblies stored in the spent fuel pool.

(2) The fuel transfer tube isolation valves are used as boundaries for the SF to ensure adequate cooling (by maintaining adequate coolant).

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

(2) Maintain pressure boundary of the SF.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

UFSAR References

9.9

Components Subject to AMR

Table 2.3.3-3 lists the spent fuel cooling system component types that require an AMR and their associated component intended functions.

Table 3.3.2-3 provides the results of the AMR.

Table 2.3.3-3
Spent Fuel Cooling System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Filter	Pressure boundary
Flow element	Pressure boundary
Heat exchanger (spent fuel pool)	Heat transfer Pressure boundary
Instrument	Leakage boundary (spatial) Pressure boundary
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing	Leakage boundary (spatial) Pressure boundary
Steel components adversely affected by boric acid leakage	Pressure boundary
Strainer	Leakage boundary (spatial)
Tank (demineralizer)	Pressure boundary
Thermowell	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.4. Waste Disposal

Description

The waste disposal (WD) systems for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units. The waste disposal system provides all the equipment necessary to collect, process, and prepare for disposal all potentially radioactive liquid, gaseous, and solid wastes produced as a result of plant operation. Radioactive fluids entering the waste disposal system are collected in sumps and tanks until determination of subsequent treatment methods can be made. Design of the WD system is based on assuring that the consequences of a radioactive release from a sub-system or component do not pose a hazard to public health and safety.

The principal components of the WD system within the scope of SLR are the waste gas and waste liquid containment penetration isolation components, waste disposal system heat exchangers with component cooling water interfaces, and the associated piping and valves to support the system intended functions. Additionally, components with a leakage boundary (spatial) 10 CFR 54.4(a)(2) intended function include components in the general area of the PAB, including: piping, valves, and components associated with the waste liquid portion of this system and the seal water portion of the waste gas compressors. Some components are credited at PBN for flood control and service water system isolation from waste disposal system components.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. System interfaces include:

Service water system

- Boric acid waste evaporator vacuum system heat exchanger on SLR-684J971 Sheet 1

Steam generator blowdown system

- Valves 1, 1A, 2, and 2A on SLR-PBM-225

Chemical and volume control system

- Reactor makeup water connection on SLR-684J971 Sheet 1
- Valves 1CV-312 and 1BS-1100 on SLR-684J971 Sheet 1A

Spent fuel cooling system

- Valve 1-816 on SLR-684J971 Sheet 1A

Service air system

- Valve 1682 on SLR-684J971 Sheet 1

Reactor coolant system

- Valves 1-523A, 1RC-527, 2-1731, 2-1728, 2-1409A on SLR-684J971 Sheet 1A

Safety injection system

- Valves 1-1729, 1SI-844A, and 1SI-844B on SLR-684J971 Sheet 1A

Residual heat removal system

- Valve 817A on SLR-684J971 Sheet 1

Component cooling water system

- Valves 1CC-732A, 1CC-732B, 1CC-732D, and 1CC-732E on SLR-684J972 Sheet 1

There are no significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort except in relation to the abandonment of the blowdown evaporator system.

PBN Unit 1:
None

PBN Unit 2:
None

PBN Common:
SLR-684J971 Sheet 1
SLR-684J971 Sheet 1A
SLR-684J971 Sheet 2
SLR-684J972 Sheet 1
SLR-PBM-225

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide pressure boundary of safety related heat exchangers.

(2) Provide isolation of lines penetrating containment to maintain the containment pressure boundary.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the commission's regulations for environmental qualification.

UFSAR References

5.2
11.1
11.2
11.3

Components Subject to AMR

Table 2.3.3-4 lists the waste disposal system component types that require an AMR and their associated component intended functions.

Table 3.3.2-4 provides the results of the AMR.

Table 2.3.3-4
Waste Disposal System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Compressor casing	Leakage boundary (spatial)
Drain trap	Leakage boundary (spatial)
Flow indicator	Leakage boundary (spatial)
Heat exchanger (waste evaporator distillate cooler)	Leakage boundary (spatial)
Heat exchanger (waste gas compressor)	Leakage boundary (spatial) Pressure boundary
Instrument	Leakage boundary (spatial)
Level gauge	Leakage boundary (spatial)
Orifice	Leakage boundary (spatial)
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pump casing	Leakage boundary (spatial)
Sight glass	Leakage boundary (spatial)
Steel components adversely affected by boric acid leakage	Leakage boundary (spatial) Pressure boundary
Strainer	Leakage boundary (spatial)
Tank (boric acid waste evaporator water separator tank)	Leakage boundary (spatial)
Tank (reagent tank)	Leakage boundary (spatial)
Tank (waste condensate polishing demineralizer)	Leakage boundary (spatial)
Tank (waste condensate tank)	Leakage boundary (spatial)
Tank (waste distillate tank)	Leakage boundary (spatial)
Tank (waste evaporator concentrator)	Leakage boundary (spatial)
Tank (waste evaporator distillate tank)	Leakage boundary (spatial)
Tank (waste evaporator feed tank/heater)	Leakage boundary (spatial)
Tank (waste evaporator hot water expansion tank)	Leakage boundary (spatial)
Tank (waste gas moisture separator)	Leakage boundary (spatial)
Tank (waste holdup tank)	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial) Pressure boundary

Note: The boric acid waste evaporator vacuum system heat exchanger (HX-702) is addressed in Section 2.3.3.5.

2.3.3.5. Service Water

Description

The SW system provides cooling water to various essential and non-essential services throughout the plant. It provides the flow path to and from Lake Michigan, which serves as the ultimate heat sink. The six motor-driven SW pumps take their suction from the pump bays in the circulating water pump house (raw water from Lake Michigan) and discharge into a loop supply header. This supply header is capable of being split (via isolation valves) into two (2) separate headers. Essential services are capable of being supplied from either header. Non-essential services are capable of being automatically isolated from the supply headers. The return lines discharge to the circulating water discharge in either Unit 1 and/or Unit 2. Under the conditions of a loss-of-coolant accident (LOCA), the service water system is capable of providing the necessary cooling capacity for the essential loads for the affected unit and supply service water for the normal operation of the unaffected unit. This is the most limiting heat load for the service water system.

The supply of service water for essential (and safety-related) services is redundant and can be maintained in case of failure of one header. The service water system supplies the following essential loads:

- Primary Auxiliary Building (PAB) battery room coolers HX-105A and HX-105B (addressed in essential ventilation, Section 2.3.3.10)

- Emergency diesel generator (G01 and G02) engine coolant heat exchangers HX-055A and HX-055B (addressed in emergency power, Section 2.3.3.8)

- Component cooling water (CCW) heat exchangers HX-012B, HX-012C, 1HX-012A, and 2HX-012D (addressed in component cooling, Section 2.3.3.2)

- Containment ventilation fan motor coolers (accident fan motor coolers 1HX-015A through D and 2HX-015A through D) (addressed in containment ventilation, Section 2.3.3.9)

- Containment ventilation coolers 1HX-015A1 through A8, 1HX-015B1 through B8, 1HX-015C1 through C8, 1HX-015D1 through D8, 2HX-015A1 through A8, 2HX-015B1 through B8, 2HX-015C1 through C8, and 2HX-015D1 through D8 (addressed in containment ventilation, Section 2.3.3.9)

- Long-term supply to the turbine driven and motor driven auxiliary feedwater pump suction, in the absence of normal supply from the condensate storage tank (addressed in auxiliary feedwater, Section 2.3.4.3)

The service water system also provides cooling water to the spent fuel pool heat exchangers, HX-013A and HX-013B, which are safety-related but considered non-essential for spent fuel decay heat removal Section 2.3.3.3). The service water system is considered a closed system inside containment.

The safety-related essential loads discussed above also constitute the scope and boundaries with respect to the recommendations of Generic Letter (GL) 89-13, which addressed reoccurring problems identified in open-cycle service water systems at various nuclear generating facilities. Auxiliary feedwater turbine-driven pump bearing oil coolers 1HX-237 and 2HX-237 (addressed in auxiliary feedwater, Section 2.3.4.3), which are also included under the GL 89-13 program, are normally cooled with treated water from the respective condensate storage tank instead of raw water.

Non-essential heat exchangers, coolers, and cooling coils that are in the same lines as essential loads include:

- HX-38A1-4 and HX-38B1-4, control room and cable spreading room condensers (addressed in essential ventilation, Section 2.3.3.10)
- HX-66 and HX-66A, auxiliary feed pump room coolers (addressed in essential ventilation, Section 2.3.3.10)
- HX-98, RHR pump room cooling coil (addressed in essential ventilation, Section 2.3.3.10)
- HX-99, containment spray area cooling coil (addressed in essential ventilation, Section 2.3.3.10)
- HX-702, boric acid waste evaporator vacuum
- P-38A/B, standby steam generator feed pump bearing coolers (addressed in auxiliary feedwater, Section 2.3.4.3)

HX-702 is a stainless steel component with a raw water internal environment and an unconditioned air external environment. The HX-702 material and environment combinations are reflected in Table 3.3.2-5.

The service water system also supplies water for the fire hose reels within containment and for the fire protection sprinkler systems in the emergency diesel generator (G01 and G02) rooms. Many other non-essential loads are supplied by service water system but are capable of being automatically isolated during accident conditions.

The service water system is treated to control biological fouling, including a silt dispersant and biodetergent injection system that injects into the suction header of the SW. The SW system includes the pumps, strainers, heat exchangers, and associated piping and valves to support the system intended functions. The service water system is normally in service during plant operation and shutdown.

The in-scope portion of the service water system consists of the safety-related supply and return headers, including the pumps, expansion joints, piping and valves up to essential heat exchangers, as well as quality-related coolers and heat exchangers in the same line, addressed in other systems. Much of the service water return header and certain heat exchangers and area coolers are non-safety related but included in-scope up to manual isolation valves, in accordance with 10 CFR 54.4(a)(2) scoping criteria. The portions of the service water system containing components subject to an AMR extend from pump bays to the CW discharge, including connections to the fire protection and auxiliary feedwater systems.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. There are significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort.

The SLR boundaries interface with essential heat exchangers/coolers, as described above, and other in-scope systems:

- steam generator blowdown downstream of valves MS-311 and MS-312 (SLR-M-201 Sheet 3 and SLR-M-2201 Sheet 3) addressed in main and auxiliary steam (Section 2.3.4.2);
- fire protection backup to the service water pumps at valve 570 (SLR-M-207 Sheet 1), and emergency diesel generator (G01 and G02) room sprinkler systems (SLR-M-207 Sheet 1A) addressed in fire protection (Section 2.3.3.6); and
- waste processing upstream of valves SW-766 and SW-769 (SLR-M-207 Sheet 3) addressed in waste disposal (Section 2.3.3.4).

The SLR boundaries include components that satisfy the 10 CFR 54.4(a)(2) criteria due to the potential impact on safety-related components from leaking fluid. These include:

- service water return header from the outlet of the heat exchangers/coolers serviced by the SW system (SLR-M-207 Sheet 1A, SLR-M-207 Sheet 3, SLR-M-207 Sheet 4, SLR-M-2207 Sheet 1, and SLR-M-2207 Sheet 2)
- interface with the circulating water discharge header (center region of SLR-M-207, Sheet 1)
- auxiliary building cooling coils, HX-32A/B; compressor aftercoolers, HX-49A/B and HX-50B, blowdown vent condenser, 1/2HX-150; Zurn strainer, Z-103, and associated piping and valves downstream of isolation valves MOV-2816, MOV-4479, TV-LW61 and TV-LW62 for automatic isolation of non-essential loads (SLR-M-207 Sheet 1A and Sheet 3, and SLR-M-2207 Sheet 2).

Though not highlighted on the SLR boundary drawings, piping and piping components attached to safety-related SSCs also satisfy the 10 CFR 54.4(a)(2) criteria and are in the scope of SLR and subject to AMR.

PBN Unit 1:
SLR-M-201 Sheet 3
SLR-M-207 Sheet 1
SLR-M-207 Sheet 1A
SLR-M-207 Sheet 2
SLR-M-207 Sheet 3
SLR-M-207 Sheet 4

PBN Unit 2:
SLR-M-2201 Sheet 3
SLR-M-2207 Sheet 1
SLR-M-2207 Sheet 2

PBN Common:
SLR-PBM-232
SLR-PBM-232A

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide emergency heat removal form the reactor coolant system using secondary heat removal capability.

(2) Provide heat removal from and/or pressure boundary of safety related heat exchangers.

(3) Provide isolation of lines penetrating containment to maintain the containment pressure boundary.

(4) Provide emergency heat removal from primary containment and provide containment pressure control.

(5) Maintain emergency temperatures within areas containing safety class 1, 2, and 3 components.

(6) Ensure adequate cooling in the spent fuel pool.

(7) Provide a long-term water source for the auxiliary feedwater system (in the absence of the normal, condensate storage tank source).

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection program.

UFSAR References

5.2
6.3
9.6
9.9

Components Subject to AMR

Table 2.3.3-5 lists the service water system component types that require AMR and their associated component intended functions.

Table 3.3.2-5 provides the results of the AMR.

Table 2.3.3-5
Service Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Expansion joint	Pressure boundary
Flow element	Pressure boundary
Heat exchanger (aftercooler)	Leakage boundary (spatial)
Heat exchanger (blowdown vent condenser)	Leakage boundary (spatial)
Heat exchanger (boric acid waste evaporator vacuum system)	Leakage boundary (spatial) Pressure boundary
Heat exchanger (gas sample analyzer)	Leakage boundary (spatial)
Heater/cooler (area coolers)	Leakage boundary (spatial)
Hose reel	Pressure boundary
Instrument	Leakage boundary (spatial) Pressure boundary
Orifice	Leakage boundary (spatial) Pressure boundary Throttle
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary
Sight glass	Leakage boundary (spatial) Pressure boundary
Steel components adversely affected by boric acid leakage	Leakage boundary (spatial) Pressure boundary
Strainer	Filter Leakage boundary (spatial) Pressure boundary
Thermowell	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.6. Fire Protection

<u>Description</u>

The fire protection program is focused on protecting the safety of the public, the environment, and plant personnel from a plant fire, and its potential effect on safe reactor operations. The fire protection program has transitioned to a risk-informed, performance-based program based on NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants." NFPA 805 components not specifically residing within the fire protection (FP) system are addressed within the individual systems for those components.

The principal components of the FP system are the main firewater loop, a diesel driven and motor-driven fire pump, jockey pump, accumulator, hose stations, hydrants, hoses, spray/sprinkler heads, nozzles, fuel oil day-tank, fuel oil supply to the diesel-driven fire pump, and the associated piping and valves to support the system functions. Also included are two fixed Halon gas suppression systems and the required gas cylinders, nozzles, and the associated piping and valves to support the Halon system's intended functions.

Additionally, the FP system includes the reactor coolant pump (RCP) oil collection sub-system that contains leakage from the RCPs' lubricating oil system to reduce the possibility of a fire in accordance with the requirements of NFPA 805. The principal components of the RCP oil collection sub-system are the enclosures, drip pans, covers, oil collection tanks, piping, and valves.

Those structural commodities such as fire damper housings, fire doors, penetration seals, etc., are addressed in plant structures. Additionally, fire detection and alarm devices are active components and do not require an aging management review. The fire protection system is a standby system during normal plant operation.

Boundary

The FP system boundaries are reflected on the SLR boundary drawings listed below. The only significant difference between the SLR boundaries and the boundaries identified as part of the original PBN license renewal effort is that due to replacement of the diesel driven fire pump engine, the old heat exchanger was removed and replaced by a cooler that is now integral to the engine skid rather than being a separate unit. This heat exchanger is now considered to be a part of the engine complex assembly and is not subject to AMR. There are no changes to other passive components that are subject to AMR associated with the engine.

PBN Unit 1:
SLR-M-208 Sheet 4
SLR-M-208 Sheet 5

PBN Unit 2:
SLR-M-208 Sheet 2

PBN Common:
SLR-M-208 Sheet 1
SLR-M-208 Sheet 6
SLR-M-208 Sheet 7
SLR-M-208 Sheet 8
SLR-M-208 Sheet 9
SLR-M-208 Sheet 10
SLR-M-208 Sheet 11
SLR-M-208 Sheet 12
SLR-M-208 Sheet 13
SLR-M-208 Sheet 14
SLR-M-208 Sheet 15

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

None.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

None.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission’s regulations for the fire protection program.

UFSAR References

9.10

Components Subject to AMR

Table 2.3.3-6 lists the fire protection system component types that require an AMR and their associated component intended functions.

Table 3.3.2-6 provides the results of the AMR.

Table 2.3.3-6
Fire Protection System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator	Pressure boundary
Bolting	Mechanical closure
Compressor casing	Pressure boundary
Expansion joint	Pressure boundary
Fire hydrant	Pressure boundary
Flame arrestor	Fire prevention
Hose reel	Pressure boundary
Instrument	Pressure boundary
Nozzle	Pressure boundary Spray
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Pump casing	Pressure boundary
RCP oil collection	Pressure boundary
Sight glass	Pressure boundary
Silencer	Pressure boundary
Steel components adversely affected by boric acid leakage	Pressure boundary
Strainer	Filter Pressure boundary
Tank (accumulator)	Pressure boundary
Tank (diesel fire pump fuel oil day)	Pressure boundary
Valve body	Pressure boundary

2.3.3.7. Heating Steam

Description

The heating steam system uses steam supplied from the house heating boilers or from a connection in the main and auxiliary steam system to heat areas of the plant. The system supports habitability and equipment reliability by maintaining plant area temperatures within acceptable bounds. In addition to supporting ventilation functions, the heating steam system also provides process steam for other plant support functions.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. There are some differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort. On both SLR-M-214 Sheet 1 and 2, the section of the heating steam system with the boric acid evaporator has been removed from the drawings and therefore is no longer within the boundary of subsequent license renewal.

PBN Unit 1:
SLR-M-214 Sheet 2

PBN Unit 2:
None

PBN Common:
SLR-M-214 Sheet 1
SLR-M-2214

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

None

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None

UFSAR References

None

Components Subject to AMR

Table 2.3.3-7 lists the heating steam system component types that require an AMR and their associated component intended functions.

Table 3.3.2-7 provides the results of the AMR.

Table 2.3.3-7
Heating Steam System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Heater/cooler	Leakage boundary (spatial)
Piping	Leakage boundary (spatial)
Piping and piping components	Leakage boundary (spatial)
Pump casing	Leakage boundary (spatial)
Steam trap	Leakage boundary (spatial)
Steel components adversely affected by boric acid leakage	Leakage boundary (spatial)
Strainer	Leakage boundary (spatial)
Tank (cond return pump cond receiver)	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial)

2.3.3.8. Emergency Power

Description

The emergency power system is designed to provide emergency/backup power to the station, in the event of a loss of normal power. The emergency power system consists of four diesel generators (G-01, G-02, G-03 and G-04) and a gas turbine generator (G-05). The normal source of power to the safety related 4.16 kV and 480V buses is from offsite power through the station low voltage auxiliary transformers. If this normal source fails, the standby source of power is the emergency diesel generators (DG). The DG portion of the emergency power system is composed of four diesel generators that directly supply the safety related 4.16kV power system. In the unlikely event of a loss of all offsite and onsite AC power, the nonsafety-related gas turbine (GT) generator is available to power the required loads until a DG or offsite power is restored.

Each DG engine is equipped with a turbocharger, air start, intake/exhaust air, lube oil, cooling water, fuel oil, and ventilation sub-systems to support system intended functions. Ventilation is addressed in the essential ventilation system (2.3.3.10). The gas turbine is provided with a starting diesel, auxiliary power supply diesel, and lube oil, cooling air, cooling water, and fuel oil sub-systems, to support system intended functions. The emergency power support sub-systems include all components up to the EDG engine power blocks and GT power block. The DG and GT power blocks and components within the power blocks are considered complex assemblies (active components) and are not subject to an AMR. The G-01/02 and G-03/04 utilize different types of cooling for the closed loop cooling water sub-systems. For the G-01/02 EDGs, heat exchangers using service water cool the closed treated water EDG cooling systems. For the G-03/04 EDGs, radiators are used to cool the closed treated water EDG cooling systems.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. The previous boundary drawings for the gas turbine system have been replaced and are now shown on SLR- ICGWH003M050000 sheets 1 through 11 which are entitled Unit 5.

PBN Unit 1:
None

PBN Unit 2:
None

PBN Common:

EDG Air
SLR-M-209 Sheet 12
SLR-M-209 Sheet 14
SLR-M-209 Sheet 15
SLR-M-226 Sheet 1
SLR-M-226 Sheet 2

EDG Fuel Oil
SLR-M-219 Sheet 1
SLR-M-219 Sheet 2
SLR-M-219 Sheet 3

EDG Cooling Water and Lube Oil
SLR-M-227 Sheet 1
SLR-M-227 Sheet 2
SLR-MKW-6090F03001 Sheet 1
SLR-MKW-6090F04001 Sheet 1
SLR-M-207 Sheet 1A

Gas Turbine
SLR-ICGWH003M050000 Sheet 1
SLR-ICGWH003M050000 Sheet 2
SLR-ICGWH003M050000 Sheet 3
SLR-ICGWH003M050000 Sheet 4
SLR-ICGWH003M050000 Sheet 5
SLR-ICGWH003M050000 Sheet 6
SLR-ICGWH003M050000 Sheet 7
SLR-ICGWH003M050000 Sheet 8
SLR-ICGWH003M050000 Sheet 9
SLR-ICGWH003M050000 Sheet 10
SLR-ICGWH003M050000 Sheet 11

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Sense or provide process conditions and generate signals for reactor trip and engineered safety feature actuation

(2) Provide electrical power to safety class 1, 2, and 3 components

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for fire protection and SBO programs.

UFSAR References

8.8
8.9

Components Subject to AMR

Table 2.3.3-8 lists the emergency power system component types that require an AMR and their associated component intended functions.

Table 3.3.2-8 provides the results of the AMR.

Table 2.3.3-8
Emergency Power System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Air Motor	Pressure boundary
Bolting	Mechanical closure
Drain trap	Pressure boundary
Expansion joint	Pressure boundary
Fan housing	Pressure boundary
Filter	Filter Pressure boundary
Flame arrestor	Fire prevention
Flow element	Pressure boundary
Flow indicator	Pressure boundary
Heat exchanger (G-01/02 EDG cooling water)	Heat transfer Pressure boundary
Heat exchanger (G-01/02 and G-03/04 EDG lube oil coolers)	Heat transfer Pressure boundary
Heat exchanger (G-03/04 EDG cooling water radiator)	Heat transfer Pressure boundary
Heat exchanger (G-05 GT cooling water)	Heat transfer Pressure boundary
Heat exchanger (G-05 GT low/high pressure air coolers)	Heat transfer Pressure boundary

Table 2.3.3-8
Emergency Power System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Heat exchanger (G-05 GT lube oil coolers)	Heat transfer Pressure boundary
Instrument	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pump casing	Pressure boundary
Sight glass	Pressure boundary
Silencer	Pressure boundary
Strainer	Filter Pressure boundary
Tank (EDG coolant expansion)	Pressure boundary
Tank (EDG day)	Pressure boundary
Tank (EDG dry starting air receivers)	Pressure boundary
Tank (EDG fuel oil storage)	Pressure boundary
Tank (EDG starting air receivers)	Pressure boundary
Tank (emergency fuel oil storage)	Pressure boundary
Tank (fuel oil storage)	Pressure boundary
Tank (GT fuel oil)	Pressure boundary
Tank (GT glycol expansion)	Pressure boundary
Tank (GT instrument air receiver)	Pressure boundary
Turbine casing	Pressure boundary
Turbo-charger	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.9. Containment Ventilation

Description

The containment ventilation system provides for emergency heat removal from the containment atmosphere, containment pressure control, and containment isolation.

The containment ventilation system is made up of the following heating and ventilating sub-systems:

- Containment cooling sub-system (VNCC)
- Containment purge supply and exhaust sub-system (VNPSE)
- Control rod drive (CRDM) cooling sub-system (VNCRD)
- Reactor cavity cooling sub-system (VNRC)
- Refueling cavity ventilation sub-system (VNRF)
- Containment cleanup sub-system (VNCF)

The post accident containment ventilation sub-system (PACV) is addressed separately in the containment hydrogen detectors and recombiner system (2.3.3.13).

Of these sub-systems, only VNCC, VNRC, and VNPSE are in-scope for SLR. The other sub-systems were reviewed and determined not to be in-scope due to having no license renewal intended function.

The principal components of the containment cooling sub-system include filters, fans, dampers, heat exchangers, ductwork and the associated piping and valves to support the system intended functions. Each air-cooling unit consists of an inlet screen, roughing filter, cooling coil, vane axial fans, back draft damper housings, and a discharge header that is common to all four units. Roughing filters are installed during refueling outages when a significant potential for a dusty containment atmosphere exists. Each cooling coil in an air-handling unit transfers heat to the service water system during normal plant operation and for limiting design basis accident conditions. In the event of a loss-of-coolant accident, these cooling units have sufficient capacity to maintain the containment temperature and pressure within design limits.

The fans, motors, electrical connections and all other equipment in the containment necessary for operation of the system under accident conditions are capable of operating under the environmental conditions existing following a loss-of-coolant accident. The containment cooling sub-system is in service during normal plant operation and design basis accident conditions.

This containment purge supply and exhaust sub-system is independent of any other system and includes provisions to both supply and exhaust air from the containment. Purging of the containment is prohibited unless the reactor is in the cold shutdown mode due to containment isolation criteria. That portion of the containment purge sub-system requiring an AMR includes the inboard blind flanges and outboard containment isolation valves, and associated piping and valves to support the system intended function.

The reactor cavity cooling sub-system consists of cooling coils, fans, and ductwork and is arranged to supply cooled air to the annulus between the reactor vessel and the primary shield and to the nuclear instrumentation external to the reactor. One hundred percent redundancy is provided by a standby fan. The cooling coils do not contain cooling service water but are maintained for air flow resistance.

The containment ventilation ductwork (except the CRDM cooling system ductwork), fans (except the refueling water surface supply and exhaust fans and the CRDM cooling system fans), filters, coils, and housings within the containment are designed as Seismic Class I components.

The portions of the containment ventilation system containing components subject to an AMR include the equipment necessary to provide emergency heat removal from the containment atmosphere and containment pressure control, and equipment necessary for containment isolation.

<u>Boundary</u>

The SLR boundaries are reflected on the SLR boundary drawings listed below. These SLR boundary drawings include components that were added since the submittal of the initial license renewal application for PBN. These components are associated with the backup nitrogen gas supply for new feedwater isolation valves and are screened as part of the instrument air system.

In addition, the service water supply to the reactor cavity cooling sub-system was removed so the associated coils are no longer needed for service water pressure boundary. However, the entire reactor cavity cooling sub-system was added to the scope of SLR because the system is needed to maintain concrete temperature below those assumed in the primary shield wall structural analysis.

The subsequent license renewal boundaries include interfaces with other systems as can be seen on drawing SLR-PBM-332 at E-8 (1T-188), E-5 (1T-223A), E-4 (1T-223B), and E-1 (1T-190) and on SLR-PBM-2332 at E-7 (2T-188), F-4 (2T-223A), E-2 (2T-223B), and E-1 (2T-190). The accumulators are included in the instrument air system, however the associated valves and piping connecting them to the VNPSE system are included in this AMR.

PBN Unit 1:
SLR-M-215 Sheet 1
SLR-PBM-332

PBN Unit 2:
SLR-M-2215 Sheet 1
SLR-PBM-2332

PBN Common:
None

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide isolation of lines penetrating containment to maintain the containment pressure boundary.

(2) Provide emergency heat removal from primary containment and provide containment pressure control.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

(2) The VNRC system maintains reactor cavity concrete temperatures below 150°F.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission’s regulations for fire protection and the EQ program.

UFSAR References

5.2
5.3
6.3

Components Subject to AMR

Table 2.3.3-9 lists the containment ventilation system component types that require an AMR and their associated component intended functions.

Table 3.3.2-9 provides the results of the AMR.

Table 2.3.3-9
Containment Ventilation System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Boot seal	Pressure boundary
Damper housing	Pressure boundary
Duct	Pressure boundary Structural integrity (attached)
Fan housing	Pressure boundary
Filter	Pressure boundary
Heat exchanger (cavity cooler)	Pressure boundary
Heat exchanger (containment vent cooling)	Heat transfer Pressure boundary
HVAC closure bolting	Pressure boundary
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Steel components adversely affected by boric acid leakage	Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

2.3.3.10. Essential Ventilation

Description

The essential ventilation system is made up of the following sub-systems that provide heating, ventilation, and air conditioning (including chilled water) for their respective areas and associated equipment contained within those areas:

- Control room ventilation sub-system (VNCR)
- Computer room ventilation sub-system (VNCOMP)
- Cable spreading room ventilation sub-system (VNCSR)
- PAB battery and inverter room ventilation sub-system (VNBI)
- Diesel generator building ventilation sub-system (VNDG)

- PAB ventilation sub-system (VNPAB)
- Circulating water pump house ventilation sub-system (VNPH)
- Radwaste ventilation sub-system (VNRAD)
- Drumming area ventilation sub-system (VNDRM)
- Battery room ventilation sub-system (VNBR)
- Auxiliary feedwater area ventilation sub-system (VNAFW)
- Gas turbine building ventilation sub-system (VNGT)

Of those sub-systems, only VNCR, VNCOMP, VNCSR, VNBI, VNPAB, and VNDG are in scope. The other sub-systems were reviewed and determined not to meet the scoping requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) with the exception of the area cooling coils HX-66 and HX-66A associated with the VNAFW system which are in scope for service water pressure boundary only.

The VNCR, VNCOMP, and VNCSR sub-systems provide radiological habitability for the control and computer rooms, which are both within the control room envelope. The sub-systems are capable of operating in five different modes providing for control room pressurization to limit in-leakage, makeup and recirculation through HEPA and charcoal filters to remove contaminants, and recirculation without filtration or makeup. The sub-systems also provides the capability to exhaust smoke from the control room, computer room, or cable spreading room through a dedicated smoke and heat vent fan.

The VNBI sub-system controls the PAB battery room temperatures to maintain the station batteries, inverters, and other safety related components within safe operating temperature limits, including during plant fires. The VNBI sub-system is classified as seismic Class I.

The VNDG sub-system maintains ambient temperatures in the required areas within acceptable limits to support the operation of the four emergency diesel generators (G01, G02, G03 and G04) during a design basis accident, loss of offsite power, SBO events, and some plant fires. G03/G04 draw outside air for combustion rather than room air like the G01/G02 diesel generators. The sub-system provides combustion and ventilation air to the emergency diesel generator room to maintain the room within operating temperature and pressure limits. The VNDG sub-system is classified as seismic Class I.

The VNPAB provides sufficient control of building temperatures during normal, abnormal, and accident conditions to maintain equipment within operational temperature limits. This system also filters the exhaust from rooms potentially containing iodine vapor, and rooms potentially containing particulates, during normal and accident conditions to limit offsite releases, and support auxiliary building habitability.

The portions of the essential ventilation system containing components subject to an AMR include filters, fans, damper housings, valves, heat exchangers, ductwork, and the associated piping and valves to support the system intended functions. Non-safety related condensate drains associated with in scope coolers are subject to AMR due to the potential for leakage on nearby safety-related equipment. Coolers that are not in scope do not have condensate drains that have the potential for leakage on safety related equipment.

In accordance with Table 2.1-2 of NUREG-2192, the chiller evaporator units HX-38A and HX-39B shown on drawing SLR-M-214 Sheet 4 associated with the control room and cable spreading room chilled water system are considered to be part of a complex refrigerant chiller assembly and are tested to ensure they function as intended. Therefore, these chiller units are on dedicated skids and are not subject to AMR. The passive chilled water system piping and piping components connected to these evaporators such as valves, piping, and the expansion tanks are subject to AMR.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. There are differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort, primarily driven by the installation of a back-up filtration system on the control building roof to provide filtered outdoor air to the control room in support of the alternate source term (AST) license amendment. In addition, the auxiliary feedwater room, residual heat removal room and containment spray pump area coolers are now screened as part of the essential ventilation system as opposed to the service water system.

The license renewal boundaries include interfaces with components that may fall into the scope of 10 CFR 54.4(a)(2) due to the potential impact on safety related components from leaking fluid. These include treated water interfaces with system heat exchangers, including those on SLR-M-144, Sheet 2 (D-6).

PBN Unit 1:
None

PBN Unit 2:
None

PBN Common:
SLR-M-143
SLR-M-144 Sheet 1
SLR-M-144 Sheet 2
SLR-M-144 Sheet 3
SLR-M-211 Sheet 3
SLR-M-214 Sheet 4
SLR-PBM-250

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide environmental climate control to the inverter and station battery rooms for the VNBI sub-system.

(2) Provide cooling to the EDG rooms when the EDGs are operating to maintain environmental limits for equipment, provide combustion air to the EDGs, and provide ventilation to support operation of the EDGs during DBAs for the VNDG sub-system.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain control room envelope to limit unfiltered leakage for the VNCOMP, VNCR, and VNCSR sub-systems, and filter and remove particulate and iodine from the outside air during emergency operations to support control room occupancy.

(2) Maintain temperatures in the auxiliary building residual heat removal and containment spray pump areas following a LOCA to maintain equipment within operational temperature limits using the VNPAB sub-system.

(3) Provides exhaust of post-LOCA airborne radionuclides from engineered safety feature system leakage via the VNPAB exhaust stack.

(4) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for fire protection, SBO and the EQ program.

UFSAR References

8.7
8.8
9.5
9.8

Components Subject to AMR

Table 2.3.3-10 lists the essential ventilation system component types that require AMR and their associated component intended functions.

Table 3.3.2-10 provides the results of the AMR.

MCR air conditioning units HX-38A and HX-38B have screened out as complex assemblies as defined in Section 2.1.5.1.

Table 2.3.3-10
Essential Ventilation System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Damper housing	Pressure boundary
Duct	Pressure boundary
Fan housing	Pressure boundary
Filter	Filter Pressure boundary
Flow element	Leakage boundary (spatial) Pressure boundary
Heat exchanger (auxiliary feedwater pump room cooler) (HX-66 and HX-66A)	Pressure boundary
Heat exchanger (containment spray area cooling coil tubes) (HX-99)	Heat transfer Pressure boundary
Heat exchanger (CSR chilled water cooling coil) (HX-101A/B)	Leakage boundary (spatial)
Heat exchanger (MCR chilled water cooling coil) (HX-100A/B)	Heat transfer Pressure boundary
Heat exchanger (MCR/computer room water duct heaters) (HX-91A/B and HX-92)	Pressure boundary
Heat exchanger (PAB battery room vent coolers) (HX-105A1/2 and HX-105B1/2)	Heat transfer Pressure boundary
Heat exchanger (RHR pump room cooling coil) (HX-98)	Heat transfer Pressure boundary
Humidifier	Pressure boundary
HVAC closure bolting	Mechanical closure
Instrument	Pressure boundary
Piping[1]	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing	Leakage boundary (spatial) Pressure boundary
Strainer	Filter Leakage boundary (spatial) Pressure boundary
Tank (expansion tank T-78)	Leakage boundary (spatial)
Tank (expansion tank T-79)	Pressure boundary
Thermowell	Leakage boundary (spatial) Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

Notes

1. Piping includes condensate drain lines

2.3.3.11. Treated Water

Description

The treated water system is shared for PBN Units 1 and 2 and thus the following discussion applies to both units. This system is basically comprised of the water treatment (WT), demineralized water (DI), potable water (PW), hydrazine addition (HA), sewage treatment plant (STP), and non-radioactive liquid waste disposal (floor drains, secondary sample effluents, etc.) secondary plant sub-systems. These sub-systems treat and demineralize water, store and supply demineralized and potable water for various uses in the plant, transfer and hold sanitary waste and clean site sump discharges, and introduce hydrazine and ethanolamine to the steam generators and condensate system. The treated water system's primary function is to support other plant process systems. The principal components of the treated water system are pumps, tanks, strainers, water heaters, heat exchangers, hoses, valves and the associated piping.

The non-safety related in-scope portion of the treated water system includes the shear gate valves in the G01/G02 rooms' oily sump, eyewash/safety shower in the auxiliary feedwater pump area, equipment drains from the HVAC room above the main control room, sump pump discharge piping, and STP piping in the safety injection/containment cooling pump area. It also includes DI piping in close proximity to the containment spray and spent fuel pool pumps and the Unit 2 charging pump cubicles. Furthermore, the demineralized water and reactor makeup water headers and valves, and portions of the potable water sub-system located in the PAB are in-scope. The safety related portion of the system is limited to the containment isolation components of the DI system. These components are included in the containment isolation system (Section 2.3.2.4).

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. SLR-PBM-231, Sheet 1 contains components that form a boundary with the chemical and volume control system (Section 2.3.3.1) while SLR-PBM-231, Sheet 2 contains containment isolation valves that are included in the containment isolation system (Section 2.3.2.4). SLR-PBM-231, Sheet 2 also contains safety related component cooling water (Section 2.3.3.2) and spent fuel pool cooling components (Section 2.3.3.3). There are no significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort. Certain level instrumentation and alarms are within the scope of subsequent license renewal per 54.4(a)(2) because they are utilized to warn operators of flood conditions. These instruments and alarms are shown as in scope on the drawings but are included in the electrical screening process.

The treated water system shares a boundary with CV and waste disposal at the piping just prior to entering the Waste Holdup Tank T-19 on SLR-M-223 Sheet 3 and with the spent fuel pool system (valves 131, 132, and SF-813A) and component cooling water (valves 1/2-773) on SLR-PBM-231 Sheet 2.

PBN Unit 1:
SLR-M-223, Sheet 2
SLR-M-223, Sheet 3

PBN Unit 2:
None

PBN Common:
SLR-PBM-231, Sheet 1
SLR-PBM-231, Sheet 2

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

None.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

UFSAR References

None.

Components Subject to AMR

Table 2.3.3-11 lists the treated water system component types that require an AMR and their associated component intended functions.

Table 3.3.2-11 provides the results of the AMR.

Table 2.3.3-11
Treated Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Piping	Leakage boundary (spatial)
Piping and piping components	Structural integrity (attached)
Steel components adversely affected by boric acid leakage	Leakage boundary (spatial)
Strainer	Leakage boundary (spatial)
Tank (control room water heater)	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial)

2.3.3.12. Circulating Water

Description

The circulating water system provides a reliable supply of water from Lake Michigan to condense the steam exhausted from the low-pressure turbines. It is a non-seismic piping system whose primary function is to remove heat from the steam cycle via the main condensers. The principal components of the circulating water system (CW) are the circulating water pumps, traveling screens and screen wash pumps and the associated piping and valves.

The CW system does not perform any safety related functions. The portion of the circulating water system that is in-scope includes the screen wash piping and associated components within the service water pump room. These are in-scope of SLR in accordance with 10 CFR 54.4(a)(2) due to the potential for leakage which could prevent the performance of a service water system safety function.

The portions of the CW system containing components subject to an AMR include the flood dampers and screen wash piping, valves, and associated components.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. There are significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort due to the addition of flood dampers to the circulating water pump house (CWPH) structure floor. These dampers eliminate the possibility for flooding from the circulating water system to affect safety related service water components. These damper housings are addressed as part of plant structures in Section 2.5.1.2.

The subsequent license renewal boundaries include interfaces with the service water system as can be seen on drawings SLR-M-212, Sheet 1 at G-7 and SLR-M-2212 at A-8. The circulating water system also interfaces with the fire water system as can be seen on drawing SLR-M-212, Sheet 2 at C-7.

PBN Unit 1:
SLR-M-212 Sheet 1

PBN Unit 2:
SLR-M-2212

PBN Common:
SLR-M-212 Sheet 2

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

None.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

UFSAR References

10.1

Components Subject to AMR

Table 2.3.3-12 lists the circulating water system component types that require AMR and their associated component intended functions.

Table 3.3.2-12 provides the results of the AMR.

Table 2.3.3-12
Circulating Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Piping	Leakage boundary (spatial)
Pump casing	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial)

2.3.3.13. Containment Hydrogen Detectors and Recombiner

Description

The containment hydrogen detectors and recombiner systems (generally referred to as the post accident containment vent (PACV)) for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units. The PACV system was originally designed to maintain hydrogen concentration within the containment following a loss-of-coolant accident below the lower flammable limit. However, this functionality is no longer required in the design and licensing basis because the NRC eliminated the hydrogen release associated with a design basis loss of coolant accident from 10 CFR 50.44 and the associated requirements that necessitated the hydrogen recombiners and the containment post-accident hydrogen vent and purge system. The capability to facilitate post-accident containment purging is maintained for beyond design basis accident management.

The in-scope portion of the containment hydrogen detectors and recombiner system includes the safety related components that extend from the piping inside the containment to the containment isolation valves located outside containment. The system includes independent sample, exhaust and supply piping connections, and the associated piping and valves. Each piping connection is equipped with redundant containment isolation valves located to minimize personnel radiation exposure should valve operation be desired. Exhaust piping discharges to either the primary auxiliary building exhaust ventilation sub-system or a hydrogen recombiner (stored at one of two offsite locations).

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort. The valves and piping associated with the containment hatches and the RE-211 and RE-212 supply and return lines on boundary drawing SLR-M-224 are contained within the evaluation boundary for the containment isolation system. Similarly, the containment buildings and hatches are contained within the evaluation boundary for the containment structure and containment penetrations systems.

PBN Unit 1:
None

PBN Unit 2:
None

PBN Common:
SLR-M-224

The attached piping and valves with a structural integrity (attached) function outside containment are also within the evaluation boundary to the end of the lines or to the vent duct.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Maintain containment pressure boundary integrity at the containment penetrations including containment isolation.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for the EQ program.

UFSAR References

5.2

5.3.2.4

Components Subject to AMR

Table 2.3.3-13 lists the containment hydrogen detectors and recombiner system component types that require an AMR and their associated component intended functions.

Table 3.3.2-13 provides the results of the AMR.

Table 2.3.3-13
Containment Hydrogen Detectors and Recombiner System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Steel components adversely affected by boric acid leakage	Pressure boundary
Valve body	Pressure boundary

2.3.3.14. Plant Sampling

Description

The plant sampling systems include both the primary and secondary sampling systems. The primary sampling system provides the ability to take samples for laboratory analysis to evaluate reactor coolant and other auxiliary systems' chemistry during normal operation. In addition, this system contains isolation valves for maintaining the containment pressure boundary. The secondary sampling system provides a means to obtain samples from various secondary plant locations for laboratory analysis.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort.

PBN Unit 1:
SLR-541F092 Sheet 1
SLR-M-222 Sheet 2

PBN Unit 2:
SLR-541F448 Sheet 1
SLR-M-2222 Sheet 2

PBN Common:
None

The subsequent license renewal boundaries of the plant sampling system shown on the boundary drawings include components that form the system boundaries with the reactor coolant system, residual heat removal system, chemical and volume control system, component cooling water steam, main steam system, and treated water system. The safety related components in the plant sampling system shown on the boundary drawings are screened with the interfacing system. These interfaces are as follows:

• Reactor coolant system	Pressurizer steam space, pressurizer liquid space, and hot leg sample lines seen at E,F,G-10 on SLR-541F092 Sheet 1 and SLR-541F448 Sheet 1
• Residual heat removal system	Sample line from the RHR heat exchanger discharges seen at D-10 on SLR-541F092 Sheet 1 and SLR-541F448 Sheet 1
• Chemical and volume control system	Charging pump discharge, mixed bed demineralizer inlet and outlet sample lines seen at C,D-10 on SLR-541F092 Sheet 1 and SLR-541F448 Sheet 1
• Component cooling water system	Provides cooling water to the sample coolers seen at E,F,G,H-7 on SLR-541F092 Sheet 1 and SLR-541F448 Sheet 1. All sample coolers associated with the plant sampling system are considered to be part of the component cooling water system.
• Main steam system	Steam generator blowdown sample line seen at E,G-10 on SLR-M-222 Sheet 2 and SLR-M-2222 Sheet 2
• Treated water system	Provides demineralized water for sample line flushing seen at B-4 on SLR-541F092 Sheet 1 and SLR-541F448 Sheet 1

The remaining components in the plant sampling system are in scope due their potential to leak or spray on safety related components.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide isolation of lines penetrating containment to maintain the containment pressure boundary.

(2) Provide pressure boundary integrity at the sample connections to the RC, RH system, CV, and the main steam system.

(3) Provide pressure boundary integrity for CC (sample heat exchangers).

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for fire protection and the EQ program.

UFSAR References

9.11

Components Subject to AMR

Table 2.3.3-14 lists the plant sampling system component types that require AMR and their associated component intended functions.

Table 3.3.2-14 provides the results of the AMR.

Table 2.3.3-14
Plant Sampling System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Instrument	Leakage boundary (spatial)
Orifice	Leakage boundary (spatial)
Piping	Leakage boundary (spatial)
Piping and piping components	Leakage boundary (spatial) Structural integrity (attached)
Steel components adversely affected by boric acid leakage	Leakage boundary (spatial)
Strainer	Leakage boundary (spatial)
Tank (SGBD sample sparging and chemical addition)	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial)

2.3.3.15. Plant Air

Description

The plant air system for PBN Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units. This system includes instrument air (IA), service air (SA), and emergency breathing air (EBA) sub-systems. The IA and SA sub-systems supply compressed air throughout the plant. The IA sub-system supplies dry, oil-free air to various components for the normal operation of both units. The SA sub-system supplies non-dried, oil-free air to those plant services not requiring dry air. The EBA sub-system is no longer credited after implementation of NFPA 805 and therefore not in the scope of SLR.

The IA sub-system consists of two air compressors, air receivers, air dryer units, filters, and air header piping and valves. The air compressors and aftercoolers are cooled by the service water system (SW). Normally one IA compressor is sufficient to supply plant requirements. The instrument air sub-system is normally in continuous operation during normal plant operation and shutdown.

In order to maintain operability on loss of IA, some components use nitrogen bottles, regulators, check valves, and/or air accumulators to maintain pressure at a component for varying periods of time to support or as a backup for the subsequent license renewal component intended function (including air to the pressurizer PORVs, purge supply and exhaust boot seals, main steam isolation valves, main feedwater isolation valves, and auxiliary feedwater discharge and mini-recirc valves).

The in-scope portion of the IA sub-system includes those IA components that support the pressurizer PORVs, the IA containment isolation valves, and the main feed isolation valve operators. The compressors, air receivers, and air dryers for IA are not required as the system has sufficient accumulators and tanks to support the system intended functions following loss of the compressors.

The SA sub-system consists of two air compressors, receivers, and the SA header piping and valves. The air compressors and aftercoolers are cooled by the SW system. In addition to supplying normal SA loads, SA is also a backup supply to IA, and a backup supply to the EBA sub-system. Normally one SA compressor is sufficient to supply system demands. The SA sub-system is normally in either continuous or intermittent operation during normal plant operation and shutdown. The portions of the SA system containing components subject to an AMR include the containment isolation valves.

Most systems interface with the plant air system, but the following systems have features to allow continued operation after a loss of IA:

- Auxiliary feedwater
- Containment ventilation
- Main and auxiliary steam
- Class 1 piping/components

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. SLR-M-209, Sheets 5 and 7 contain containment isolation valves that are included in the containment isolation system (Section 3.2.2.1.4). Boundary changes since the initial license renewal include the addition of the air supplies to the new main feedwater isolation valves to support EPU, the removal of the connection to the charging pump controller and variable drives (this change removed all required components on SLR-M-209, Sheet 8), and the installation of the backup pneumatic supply to the PORVs. Additionally, removal of the EBA system via plant conversion to NFPA 805 removed all required components from SLR-M-209 Sheet 13. Other than these changes there are no other significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort. Boundaries with other systems include the feedwater system at the feedwater isolation valve actuators on SLR-M-209 Sheet 5 and Sheet 7, the reactor coolant and connected piping system at the PORVs on SLR-M-209 Sheet 11, the auxiliary feedwater system valves on SLR-M-217 Sheet 2, the safety injection system at valve 1/2SI-905 on SLR-110E017 Sheet 1 and SLR-110E035 Sheet 1, and the containment ventilation system at the purge exhaust and supply fan suction boot seals on SLR-PBM-332 and SLR-PBM-2332.

PBN Unit 1:
SLR-110E017 Sheet 1
SLR-PBM-332

PBN Unit 2:
SLR-110E035 Sheet 1
SLR-PBM-2332

PBN Common:
SLR-M-209 Sheet 2
SLR-M-209 Sheet 5
SLR-M-209 Sheet 7
SLR-M-209 Sheet 11
SLR-M-217 Sheet 2

In addition, nonsafety-related IA and backup Nitrogen piping and piping components upstream of the check valves that isolate the accumulators/tanks on the above drawings have a structural integrity (attached) function up to the seismic, or equivalent, anchor location.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) The instrument and service air sub-systems have containment isolation valves that are isolated to prevent the release of radioactivity to the environment.

(2) IA system backup accumulators provide the pneumatic motive force for auxiliary feedwater (AFW) pump minimum recirculation and flow control air operated valves (AOV).

(3) The IA system provides the pneumatic motive force for the PORVs when aligned for LTOP protection.

(4) IA system backup accumulators provide the pneumatic motive force for closure of the main feedwater isolation valves.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Performs a function that demonstrates compliance with the Commission's regulations for fire protection, SBO, and the EQ program.

UFSAR References

5.2
9.7

Components Subject to AMR

Table 2.3.3-15 lists the plant air system component types that require an AMR and their associated component intended functions.

Table 3.3.2-15 provides the results of the AMR.

Table 2.3.3-15
Plant Air System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator	Pressure boundary
Bolting	Mechanical closure
Instrument	Pressure boundary
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Steel components adversely affected by boric acid leakage	Pressure boundary
Tank (purge supply/exhaust fan suction boot seal)	Pressure boundary
Tank (PORV nitrogen backup)	Pressure boundary
Valve body	Pressure boundary

2.3.4. Steam and Power Conversion System

2.3.4.1. Main and Auxiliary Steam

Description

The main and auxiliary steam system transports the steam produced in the steam generators to the main turbine for the production of electricity. The main and auxiliary steam system also provides steam for the turbine-driven auxiliary feedwater pumps that can be obtained from either main steam line, upstream of the main steam isolation valves. The main and auxiliary steam system is in continuous operation during normal plant operation and provides heat removal from the reactor coolant system during normal, accident, and post-accident conditions. The principal components of the main and auxiliary steam system are the main steam lines and main steam isolation valves, auxiliary steam lines, and a steam generator blowdown sub-system. Each unit has two steam generators, and each steam generator has connections for each of the above principal components.

Each main steam line has four main steam safety valves and an atmospheric relief valve. The atmospheric relief valve has two functions. It offers overpressure protection to the steam generator at a set point below the main steam safety valve set points and can be used to maintain reactor coolant temperature or perform a plant cooldown in the event the steam dump to the condenser is not available. Each main steam line is also equipped with a fast closing main steam isolation valve (MSIV) and a non-return check valve. The MSIV can isolate steam flow from its steam generator, and the non-return check valve prevents reverse flow in the main steam lines. The in-scope portion of the main steam line components to support the 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3) intended functions extend from the steam generators to the seismic Class I boundary downstream of the non-return valves. The main steam components that are in scope to support the 10 CFR 54.4(a)(2) intended function include steam piping in the façade and high energy piping near the main feedwater regulating valves.

Steam is supplied to the turbine-driven auxiliary feedwater pumps and radwaste steam sub-system. Each steam line has a steam admission valve for both the turbine-driven auxiliary feedwater pump and radwaste steam sub-system. The in-scope portion of the steam lines are the piping components from the main steam lines to the auxiliary feedwater pump turbines (including exhaust from the turbine), and the radwaste auxiliary steam lines in the primary auxiliary building (PAB) and inside the facade.

The steam generator blowdown sub-system is used to reduce the quantities of solids that accumulate in the steam generators as a result of the boiling process. Blowdown piping runs from the steam generator to blowdown heat exchangers and tank located outside of containment. A steam generator blowdown sample connection is also provided off of the blowdown piping. The portion of the steam generator blowdown sub-system that is in scope to support the 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3) intended functions includes the piping components that extend from the steam generators to the containment isolation valves outside containment. The remaining portions of the steam generator blowdown sub-system that is in scope to support the 10 CFR 54.4(a)(2) intended function include the blowdown heat exchangers, blowdown tank, blowdown filter pump, and associated filters, strainers, valves, and piping.

The portions of the main and auxiliary steam system containing components subject to an AMR include the main steam line components extending from the steam generators to downstream of the non-return valves, auxiliary steam lines to the turbine-driven auxiliary feedwater pumps (including exhaust piping), radwaste steam lines in the PAB and facade, components associated with the steam generator blowdown system, and sample piping components that extend from the steam generators to the containment isolation valves. The principal components of the main and auxiliary steam system are the main steam lines, auxiliary steam lines, and a steam generator blowdown sub-system. Each unit has two steam generators, and each steam generator has connections for each of the above principal components.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort.

The safety related portion of the system includes all of the piping and components on drawings SLR-M-201 Sheet 1 and SLR-M-2201 Sheet 1 with the exception of the turbine casings for the turbine driven auxiliary feedwater pumps which are included in the auxiliary feedwater system (Section 2.3.4.3) and the steam generators themselves which are included in Section 2.3.1.5.

Additional safety related components are shown on drawings SLR-M-201 Sheet 3 and SLR-M-2201 Sheet 3. These boundaries extend from the steam generator A and B blowdown lines to valves 2045 and 2042. Another section of safety related boundaries extend from the service water return header and is bounded by valves 312 and 5954.

On drawing SLR-PBM-227, the safety related portion of the system extend from the steam generators and is bounded by valves 1MS-326A and 1MS-328A, 1RS-71 and 1RS-72, 2RS-71 and 2RS-72, 2MS-326A and 2MS-328A, 2MS-326B and 2MS-328B, and RS-SA-1.

The remaining components shown on the drawings are primarily in scope in accordance with 10 CFR 54.4(a)(2) and were determined via walkdowns which evaluated where nonsafety components may impact safety-related components through spatial interactions. These boundaries are based on proximity of nonsafety components to safety-related components and may not appear sensible from the drawing alone (e.g., the boundary may be in the middle of a line segment without a nearby valve or similar component).

PBN Unit 1:
SLR-M-201 Sheet 1
SLR-M-201 Sheet 2
SLR-M-201 Sheet 3
SLR-M-203 Sheet 1
SLR-M-203 Sheet 2
SLR-M-205 Sheet 1

PBN Unit 2:
SLR-M-2201 Sheet 1
SLR-M-2201 Sheet 2
SLR-M-2201 Sheet 3
SLR-M-2203 Sheet 1
SLR-M-2203 Sheet 2
SLR-M-2204
SLR-M-2205 Sheet 1

PBN Common:
SLR-PBM-227

The (a)(1) scope extends from the steam generators and is bounded by valves 1MS-326A and 1MS-328A, 1RS-71 and 1RS-72, 2RS-71 and 2RS-72, 2MS-326A and 2MS-328A, 2MS-326B and 2MS-328B, and RS-SA-1.

The (a)(2) boundaries continue from the (a)(1) boundaries and extend to the furthest valves of all lines within the auxiliary building.

The subsequent license renewal boundaries of the main and auxiliary steam system shown on the boundary drawings include components that form the system boundaries with the following subsequent license renewal systems/components: feedwater and condensate (Section 2.3.4.2), auxiliary feedwater (Section 2.3.4.3), plant air (Section 2.3.3.15), steam generators (Section 2.3.1.5), service water (Section 2.3.3.5), and plant sampling (Section 2.3.3.14). The boundary valves are shown on the boundary drawings listed above and are generally just upstream or downstream of the continuation flags to and from the other system boundary drawings.

<u>System Intended Functions</u>

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Sense or provide process conditions and generate signals for reactor trip and engineered safety features actuation.

(2) Provide emergency heat removal from the reactor coolant system using secondary heat removal capability.

(3) Maintain containment pressure boundary integrity at the containment penetrations including containment isolation.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for the ATWS, fire protection, EQ, and SBO programs.

<u>UFSAR References</u>

5.2
7.2
7.4
10.0
10.1
10.2

Components Subject to AMR

Table 2.3.4-1 lists the main and auxiliary steam system component types that require an AMR and their associated component intended functions.

Table 3.4.2-1 provides the results of the AMR.

Table 2.3.4-1
Main and Auxiliary Steam System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Drain trap	Pressure boundary
Filter housing	Leakage boundary (spatial)
Flow element	Leakage boundary (spatial) Pressure boundary Throttle
Heat exchanger (blowdown)	Leakage boundary (spatial)
Heat exchanger (blowdown evaporator vent condenser)	Leakage boundary (spatial)
Heat exchanger (high pressure feedwater heater)	Leakage boundary (spatial)
Heat exchanger (low pressure feedwater heater)	Leakage boundary (spatial)
Level element	Leakage boundary (spatial)
Orifice	Pressure boundary
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Leakage boundary (spatial) Pressure boundary Structural integrity (attached)
Pump casing	Leakage boundary (spatial)
Rupture disc	Leakage boundary (spatial)
Steam trap	Leakage boundary (spatial) Pressure boundary
Steel components adversely affected by boric acid leakage	Leakage boundary (spatial) Pressure boundary
Strainer	Leakage boundary (spatial)
Tank (blowdown)	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.4.2. Feedwater and Condensate

Description

The feedwater and condensate system functions to condense the steam exhausted from the low-pressure turbines, collect this condensate, and then send it back to the steam generators for reuse. Components within the system are used to provide emergency heat removal from the reactor coolant system using secondary heat removal capability. The engineered safety features actuation system (ESFAS) provides actuation signals for feedwater isolation. The feedwater and condensate system is normally in continuous operation during normal plant operation.

The principal components of the feedwater and condensate system are the feedwater and condensate pumps, MFIVs, MFRVs and bypass valves, feedwater heaters, and the associated piping and valves to support the system functions. The condensate pumps take suction from the condenser hotwell and pump condensate forward through low pressure feedwater heaters to the suction of the feedwater pumps. The feedwater pumps then pump feedwater through a high-pressure feedwater heater, through the MFIVs, MFRVs and bypass valves, and to the steam generators. The MFIVs provide the primary means of isolating the main feedwater flow to a faulted steam generator. They each contain two redundant solenoid valves which energize to close the associated MFIV on a safety injection signal. The MFRVs are a backup means of feedwater isolation for a faulted steam generator but are the primary device for feedwater isolation on steam generator high-high water level and reactor trip. The bypass valves are a primary isolation device for steam generator high-high water level. Each feedwater line is equipped with two check valves in series (one inside containment and one outside of containment) to prevent reverse flow of feedwater or auxiliary feedwater away from the steam generators.

The portion of the feedwater and condensate system that contains components subject to an AMR includes components from the MFRV and bypass valves to the steam generators and piping segments near the condensate storage tanks (CSTs) bounded by the CSTs, low flow makeup valve, high flow makeup valve, manual fill valve, and valves downstream of the condensate transfer pump. Additionally, a portion of nonsafety-related feedwater and condensate piping around the steam generator blowdown heat exchangers and condensate transfer pumps are also subject to an AMR, where it is in proximity to some vulnerable safety related equipment.

<u>Boundary</u>

The SLR boundaries are reflected on the SLR boundary drawings listed below. There are no significant differences between these boundaries and the boundaries identified as part of the original PBN license renewal effort.

The safety related portion of the system includes portions of drawings SLR-M-202 Sheet 2 and SLR-M-2202 Sheet 2; these boundaries extend from the steam generators to the MFIVs (valves 3124 and 3125).

The remaining components on the drawings are in scope in accordance with 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3). The (a)(3) components are those that serve the functions described in Sections 3.3 through 3.6. The (a)(2) components were determined via walkdowns which evaluated where nonsafety components may impact safety-related components through spatial interactions. These boundaries are based on proximity of nonsafety components to safety-related components and may not appear sensible from the drawing alone (e.g., the boundary may be in the middle of a line segment without a nearby valve or similar component).

PBN Unit 1:
SLR-M-201 Sheet 3
SLR-M-202 Sheet 1
SLR-M-202 Sheet 2

PBN Unit 2:
SLR-M-2201 Sheet 3
SLR-M-2202 Sheet 1
SLR-M-2202 Sheet 2

PBN Common:
SLR-M-217 Sheet 1
SLR-PBM-228

The subsequent license renewal boundaries of the feedwater and condensate system shown on the boundary drawings include components that form the system boundaries with the following subsequent license renewal systems/components: main and auxiliary steam (Section 2.3.4.1), auxiliary feedwater (Section 2.3.4.3), steam generators (Section 2.3.1.5), service water (Section 2.3.3.5), and plant air (Section 2.3.3.15). The boundary valves are shown on the boundary drawings listed above and are generally just upstream or downstream of the continuation flags to and from the other system boundary drawings. Where the system interface is not so simple, more detailed descriptions are provided below. Also, the tube sides of feedwater heaters 4A and 5A do not fall into the scope of 10 CFR 54.4(a)(2), however the shell sides of these feedwater heaters fall into the scope of 10 CFR 54.4(a)(2) and are addressed as part of the main and auxiliary steam system. The feedwater and condensate system interfaces with the auxiliary feedwater system on drawing SLR-M-217 Sheet 1 at valves CS-173A and CS-173B. The (a)(2) portion of the feedwater and condensate system extends from the boundary valves to continuation flags for M-202 Sheet 1 D-10 and M-2202 Sheet 1 D-1.

The feedwater and condensate system interfaces with the main and auxiliary steam system on drawing SLR-M-201 Sheet 3. The condensate portion of the drawing is in scope in accordance with 10 CFR 54.4(a)(2) and extends from the façade to the blowdown heat exchangers on the condensate supply and return lines.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Sense or provide process conditions and generate signals for reactor trip and engineered safety features actuation.

(2) Provide emergency heat removal from the reactor coolant system using secondary heat removal capability.

(3) Maintain containment pressure boundary integrity at the containment penetrations including containment isolation.

(4) Isolate feedwater in the event of a faulted steam generator.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for the ATWS, fire protection, EQ, and SBO.

UFSAR References

5.2
7.2
7.4
10.1

Components Subject to AMR

Table 2.3.4-2 lists the feedwater and condensate system component types that require an AMR and their associated component intended functions.

Table 3.4.2-2 provides the results of the AMR.

Table 2.3.4-2
Feedwater and Condensate System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Flow element	Pressure boundary Throttle
Level element	Leakage boundary (spatial)
Orifice	Leakage boundary (spatial)
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Leakage boundary (spatial) Pressure boundary Structural integrity (attached)
Pump casing	Leakage boundary (spatial)
Steam trap	Leakage boundary (spatial)
Steel components adversely affected by boric acid leakage	Leakage boundary (spatial) Pressure boundary
Tank (condensate receiver)	Leakage boundary (spatial)
Thermowell	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.4.3. Auxiliary Feedwater

Description

The auxiliary feedwater system is designed to supply high-pressure feedwater to the steam generators in order to maintain a water inventory for removal of heat energy from the reactor coolant system by secondary side steam release in the event of inoperability or unavailability of the main feedwater system. One turbine-driven auxiliary feedwater (TDAFW) and one motor-driven auxiliary feedwater (MDAFW) pump per unit are provided to ensure that adequate feedwater is supplied to the steam generators for heat removal under all circumstances, including loss of power and loss of normal heat sink. Auxiliary feedwater flow can be maintained until power is restored or reactor decay heat removal can be accomplished by other systems.

The auxiliary feedwater system serves both units and consists of two electric MDAFW pumps, two TDAFW pumps, two standby steam generator (SSG) feedwater pumps, two condensate storage tanks, and the associated piping and valves to support the system functions. Redundancy is provided by utilizing two pumping systems, two different sources of power for the pumps, and two sources of water to supply the pumps. Nitrogen bottles and air accumulators are provided for plant air system backup to the auxiliary feedwater pump discharge valves and mini-flow recirculation valves. The normal water supply source for auxiliary feedwater is by gravity feed from two condensate storage tanks, while the backup safety related supply is provided by the service water system.

Cooling water for the TDAFW pump and turbine bearing lubricating oil coolers is supplied by water from the first stage of the pump discharge. Cooling water for the SSG pump bearing lubricating oil coolers is supplied by the service water system. The MDAFW pumps are air-cooled and do not require service water to cool the bearings.

The portions of the auxiliary feedwater system subject to an AMR extend from the condensate storage tanks to the steam generators.

Boundary

The SLR boundaries are reflected on the SLR boundary drawings listed below. Compared with the original PBN license renewal effort, the boundaries are expanded to include components on drawings SLR-M-217 Sheet 3 and SLR-M-2217 Sheet 1, which show the two new motor-driven auxiliary feedwater pumps and associated components. Screening of the steam supply to the TDAFW pumps is included with the main steam system (Section 2.3.4.1).

The safety related portion of the system includes all of the piping and components on drawings SLR-M-217 Sheet 2, SLR-M-217 Sheet 3, and SLR-M-2217 Sheet 1. The safety related portion of SLR-M-217 Sheet 1 includes all of the piping and components except for those portions in scope in accordance with 10 CFR 54.4(a)(2), as described below.

The (a)(2) boundary on SLR-M-217 Sheet 1 extends upstream from valves 119A and 120A toward the water treatment system interface, stopping downstream of the branch containing valve 71. Another (a)(2) boundary extends upstream from valve 118, stopping before reaching valve 69, HV-255, or the branch containing HV-261.

PBN Unit 1:
SLR-M-217 Sheet 3

PBN Unit 2:
SLR-M-2217 Sheet 1

PBN Common:
SLR-M-217 Sheet 1
SLR-M-217 Sheet 2

The subsequent license renewal boundaries of the auxiliary feedwater system shown on the boundary drawings include components that form the system boundaries with the following subsequent license renewal systems/components: main and auxiliary steam (Section 2.3.4.1), auxiliary feedwater (Section 2.3.4.2), plant air (Section 2.3.3.15), service water (Section 2.3.3.5), and steam generators (Section 2.3.1.5). The boundary valves are shown on the boundary drawings listed above and are generally just upstream or downstream of the continuation flags to and from the other system boundary drawings.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide emergency heat removal from the reactor coolant system using secondary heat removal capability.

(2) Provide heat removal from safety related heat exchangers

(3) Provide pressure boundary of safety related heat exchangers

(4) Isolate auxiliary feedwater in the event of a faulted steam generator.

(5) Maintain containment pressure boundary integrity at the containment penetrations including containment isolation.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of nonsafety-related components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

Fire protection, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for the ATWS, fire protection, EQ, and SBO programs.

UFSAR References

5.2
7.2
7.4
10.1

Components Subject to AMR

Table 2.3.4-3 lists the auxiliary feedwater system component types that require an AMR and their associated component intended functions.

Table 3.4.2-3 provides the results of the AMR.

Table 2.3.4-3
Auxiliary Feedwater System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator	Pressure boundary
Bolting	Mechanical closure
Flow element	Pressure boundary
Heat exchanger (1/2P-29 lube oil cooler)	Heat transfer Pressure boundary
Heat exchanger (P-38A/B bearing cooler)	Heat transfer Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing	Pressure boundary
Steel components adversely affected by boric acid leakage	Leakage boundary (spatial) Pressure boundary
Strainer	Pressure boundary
Tank (condensate storage tank)	Pressure boundary
Thermowell	Pressure boundary
Turbine casing	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.4. SCOPING AND SCREENING RESULTS: STRUCTURES

2.4.1. Containment Structure and Internal Structural Components

Description

The Unit 1 and 2 containment building structures consist of a prestressed, post tensioned, reinforced concrete right cylinders with flat base slabs and shallow domed roofs. Each containment structure has a 1/4 inch thick welded steel liner attached to the inside face of the concrete shell to insure a high degree of leak tightness. The structures provide biological shielding for both normal and accident situations. The Unit 2 containment is essentially identical in design and construction to that of Unit 1 except that it is oriented to conform to the overall site plan. Each containment structure is entirely housed in an unheated enclosure (façade) that provides protection from the weather.

The nominal 3-foot 6-inch-thick cylindrical wall and 3-foot-thick dome are prestressed and post-tensioned. The nominal 9-foot-thick concrete base slab is reinforced with high strength reinforcing steel. The slab is supported on H piles driven to refusal in the underlying bedrock. Bearing plates are welded to the piles to transfer the pile reaction to the concrete without exceeding the allowable concrete stresses. The piles are embedded 3 feet into the mat. The H-piles are distributed under the mat with added concentration of piles under the outer circumference of the mat where the foundation loadings are greatest due to seismic or wind overturning forces. Numerous mechanical and electrical systems penetrate the containment wall through welded steel penetrations.

Dome and Cylinder Walls and Ring Girder - The concrete placement for the walls was done in 10-foot high sections with vertical joints at the centerline of the six buttresses. The cylinder wall contains both vertical and hoop (horizontal) tendons contained in sheaths embedded in the concrete. The vertical tendons span the length of the wall from the tendon gallery ceiling to the upper surface of the dome ring girder. The vertical tendon sheaths alternate 8.5” (nominal) inside or outside the centerline of the 3-foot 6-inch thick cylinder wall. The dome covers the containment structure and consists of prestressed post-tensioned reinforced concrete that is nominally 3-foot thick. The dome contains three groups of tendons that are 120º apart from one another. Each tendon group consists of 49 parallel tendons that span the entire dome and are anchored at the outside surface of the dome ring girder. At the interface with the cylinder walls is the dome girder. The vertical outside surface of the girder between these two plant elevations has a radius of 57-feet as compared to outer cylinder wall surface radius of 56-feet. The upper surface on the girder contains the top anchorages for the vertical wall tendons. The outside surface on the girder contains the anchorages for the dome tendons.

Foundation Slabs - The concrete foundation mat serves as the structural foundation support for the containment. It varies in thickness from 8-foot thick at the center to 11-foot 6-inch thick at the outside edge. The concrete mat is reinforced with high strength reinforcing steel and is supported on H-piles. The reinforcing steel at the mat periphery is extended upward into the containment’s cylinder walls providing an integral bond between mat and wall cylinder.

A tendon gallery provides access to the lower anchors of vertical wall tendons. The gallery extends around the periphery of the foundation mat. The upper surface of the tendon gallery contains the anchorages for the vertical wall tendons. The upper 2-feet 4-inches of the gallery intrudes into the bottom of the foundation mat. Accordingly, the portion of the gallery below the foundation mat is not within the scope of license renewal.

Steel Liner Plates - The interior of each containment is lined with steel plates that are welded together. The liner plate covers the dome and cylinder walls and runs between the floor and the mat foundation to form an essentially leak-tight barrier. The liner helps assure leak tightness of the containment. The base liner is installed on top of the structural slab and is covered with concrete. The frequent anchoring of the plate to the concrete is designed to prevent significant distortion of the liner plate during accident conditions and to ensure that the liner maintains its leak tight integrity.

The exposed surface of the liner plate is coated with zinc silicate primer and an epoxy topcoat finish. No paint was applied on liner surfaces in contact with concrete. The liner plate was fabricated with a leak chase channel (LCC) system. The original purpose of the LCC was to have the ability to pressure test the liner plate or penetration welds for leaks without pressurizing the full containment structure. The LCCs presently are not used but are considered an integral part of the liner plate and therefore a part of the leak tight containment pressure boundary.

Anchors, Embedments and Attachments - Structural steel commodities include anchors, embedments, and attachments, such as angles and anchor studs, that are welded to the liner and serve to anchor each liner to the containment shells. In addition, other anchors, embedments, and attachments are provided that serve to transfer loads into the concrete cylinder walls or foundation mats from attachments to the liners. Attachments to the liner that are integral with the liner and concrete structure (i.e., attachment has corresponding anchor in concrete), include those equipment or system supports connected to the inside face of the liner and thus exposed to the interior of the containment.

The liner anchors and attachments are designed to maintain the essential leak-tight barrier by preserving the integrity of the liner. The load carrying capacity of said anchors and attachments is also required to ensure the supported equipment, such as the polar crane brackets, can continue to perform safely as required.

Fuel Transfer Tubes - The fuel transfer tube penetrates the containment to link the refueling canal inside the containment with the transfer canal in the spent fuel pit room in the primary auxiliary building. The fuel transfer tube serves as the underwater pathway for moving the fuel assemblies into and out of the containment for refueling operation during plant shutdown. As part of the containment pressure boundary, the fuel transfer tube must assure the essentially leak-tight barrier function of the containment.

Penetrations - All containment penetrations are designed to maintain the essentially leak-tight barrier to limit the release of radioactivity to ensure the requirements of 10 CFR 100 are met. In addition to supporting the essentially leak-tight barrier function, each penetration performs service- related functions. Penetrations may also serve as support points for systems, such as piping passing through the containment boundary. All piping and ventilation penetrations are of the rigid welded type and are solidly anchored to the containment wall, thus eliminating the need to use expansion bellows for containment barriers inside containment. Butt welds are used between the penetration sleeve and process piping. Both flued ends and drilled standard weight pipe caps are used for the closure piece between the sleeves and the pipes. Electrical penetrations consist of carbon steel pipe canisters with stainless steel header plates welded to each end.

Construction truss - The construction truss system provides support for the attached containment spray piping. The original function of the radial construction truss was to facilitate containment construction by acting as a concrete form. The trusses were lowered away from the liner plate after the initial 8 in. of concrete reached design strength, but prior to the placing of the balance of the dome concrete.

RC Class 1 Supports - The interface between the containment structure and the Class 1 supports is at the containment's concrete surface. The steel components comprising the support structure, including structure fasteners and exposed portion of the structure's anchorage fasteners, are part of the Class 1 support. The RC Class 1 supports are composed of the following: reactor vessel supports; steam generator supports; reactor coolant pump supports, pressurizer supports and pressurizer surge line supports.

Post-Tensioning System - The post-tensioning system for each containment consists of numerous tendons placed around the containment walls, both vertically and horizontally, and over the containment dome. The tendons are enclosed in a sheathing system, which consists of spirally wound sheet metal tubing that acts as housing for the tendons. The tendons are installed in the sheathing system, and then tensioned to predetermined values depending on the prestress required for containment integrity.

Each containment cylinder wall is prestressed by 168 vertical tendons, anchored at the top surface of the ring girder and at the bottom of the base slab, and 367 hoop tendons anchored at the six vertical buttresses. The dome consists of three groups of 49 dome tendons oriented at 120° to each other, for a total of 147 tendons anchored at the vertical face of the dome ring girder.

Boundary

The containment structure boundary is defined as the external surfaces of the containment structure. The containment structural boundary includes all the components that comprise the containment pressure boundary, which serves as the third and final barrier against the release of radioactive material to the environment. There are no significant differences between the current boundaries and those identified as part of the original PBN license renewal effort.

System Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Remain functional during and after a design basis event (DBE) to prevent the uncontrolled release of radioactivity.

(2) Provide structural support to safety-related components.

(3) Provide shelter/protection to safety-related components and provide a missile barrier to turbine-and tornado-generated missiles.

Nonsafety-related that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) The containment structures contain non safety-related SSCs which could potentially affect the satisfactory accomplishment of safety-related functions.

Fire protection, EQ, PTS functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for fire protection

(2) House and/or support EQ components and components relied on for PTS.

UFSAR References

2.5
2.8
5.1
5.1.1.1
5.1.2.6
9.4

Subsequent License Renewal Drawings

The subsequent license renewal drawing for the containment structure is LR-C-3.

Components Subject to AMR

Table 2.4-1 lists the containment structure and internal structural component types that require an AMR and their associated component intended functions.

Table 3.5.2-1 provides the results of the containment structure and internal structural components AMR.

Table 2.4-1
Containment Structure and Internal Structural Components Subject to Aging Management Review

Component Type	Intended Function(s)
Air lock, equipment hatches and accessories	Fire barrier Pressure boundary
Concrete Foundation / Basemat	Direct flow Pressure boundary Structural support
Concrete Walls, Buttresses, Dome and Ring Girder	Fire barrier Flood barrier Missile barrier Pressure boundary Shelter, protection Structural support
Concrete Internal Columns, Beams, Slabs and Walls	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support
Concrete Tendon Gallery Walls	Shelter, protection
Construction truss	Structural support
H-Piles	Structural support
Fuel transfer tube (including penetration sleeves, expansion joints and blind flange)	Fire barrier Pressure boundary Radiation shielding Structural support
Liners (refueling cavity), and covers (sand box, Unit 1 sump A strainer)	Fire barrier Pressure boundary Radiation shielding
Liners (reactor cavity)	Radiation shielding Structural support
Liner plate (containment)	Direct flow Fire barrier Pressure boundary Structural support
Liner plate and keyway channels	Direct flow Pressure boundary Structural support
Liner plate anchors and attachments	Pressure boundary Structural support
Liner plate moisture barrier (sealing compound)	Shelter, protection
Miscellaneous structural components [1]	Structural support
Penetration assemblies (elastomer)	Pressure boundary Structural support

[1] Miscellaneous structural components inside Containment include ladders, stairs, handrails, gratings such as Unit 1 flow diverters, platforms, and the RV core barrel support stand.

Table 2.4-1
Containment Structure and Internal Structural Components Subject to Aging Management Review

Component Type	Intended Function(s)
Penetration assemblies (Electrical)	Fire barrier Pressure boundary Structural support
Penetration assemblies (Mechanical)	Pressure boundary Structural support
Penetration sleeves (Electrical)	Pressure boundary Structural support
Penetration sleeves (Mechanical)	Pressure boundary Structural support
Pressure-retaining bolting	Pressure boundary Structural support
Primary shield wall (and biological shield wall)	Radiation shielding Shelter, protection Structural support
Radiant energy shields	Fire barrier
RC Class 1 supports	Structural support
RC Class 1 support bolting	Structural support
Reactor cavity seal ring	Pressure boundary
Refueling components (containment upender, davit arm)	Structural support
Service Level I coatings	Maintain adhesion
Sliding surfaces	Structural support
Tendons (post-tensioning system)	Structural support
Tendon anchorage and attachments	Pressure boundary Structural support
Thermal Insulation (high temperature penetrations)	Insulate (thermal)

2.4.2. Circulating Water Pumphouse Structure

Description

The Circulating Water Pumphouse (CWPH) structure consists of four interconnected facilities, the forebay, the CWPH building, the intake crib, and the discharge flumes. Only the forebay and CWPH building are in the scope of license renewal. In an emergency there are four separate flow paths into the forebay (two intake pipes and two discharge flumes), only one of which is needed. The intake crib (nonsafety-related) is completely submerged offshore. It connects with the forebay's surge chambers via two 14-foot diameter pipes that are buried below the lakebed. The forebay channels the lake water to the pump bay within the CWPH building. The CWPH building contains pumps for the Circulating Water system, Service Water system, and Fire Protection system. Two discharge flumes (nonsafety-related) are attached to the east wall of the forebay's seal wells and extend into Lake Michigan. Circulating water discharge from the Units 1 and 2 condensers empties into their separate seal wells via two 12-foot diameter pipes and then flows to the discharge flumes via 14-foot diameter valves.

The forebay is a reinforced concrete structure (walls, floor) set back 65 feet from the shoreline. The forebay is exposed to outdoor weather above and has vertical walls parallel and perpendicular to the shoreline that define its boundary. The forebay and CWPH are supported on a spread mat foundation upon glacial overburden above bedrock. This foundation forms the common floor of the forebay and CWPH building at elevation (-)28-feet-6-inches. The CWPH building is a seismic Class I reinforced concrete structure with its operating floor at elevation 7-feet. The superstructure is constructed of reinforced concrete walls around the periphery. Interior walls, which partially segregate the Service Water system and Fire Protection system pumps from the Circulating Water system pumps, consist of reinforced concrete. The roof is a concrete slab supported on structural steel framing. The structural steel frame is supported on concrete pilasters in the perimeter walls and steel columns in the center of the building.

Boundary

The circulating water pumphouse boundary includes all the structural components that comprise the circulating water pumphouse and forebay. There are no significant differences between the current boundaries and those identified as part of the original PBN license renewal effort.

Structure Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Support and house six service water pumps.

Nonsafety-related functions that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide nonsafety-related flood barriers.

Fire protection functions (10 CFR 54.4(a)(3)):

(1) Structurally support and house two fire water pumps and a jockey pump.

(2) Provide fire barriers.

UFSAR References

2.5
2.6
2.8
9.6
10.1

Subsequent License Renewal Drawing

The subsequent license renewal drawing for the circulating water pumphouse structure is LR-C-3.

Components Subject to AMR

Table 2.4-2 lists the Circulating Water Pumphouse structure component types that require AMR and their associated component intended functions.

Table 3.5.2-2 provides the results of the AMR.

Table 2.4-2
Circulating Water Pumphouse Structure Subject to Aging Management Review

Component Type	Intended Function(s)
Concrete basemat, foundation	Structural support
Concrete external walls and roof	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support
Concrete forebay and pump bay	Direct flow Flood barrier Shelter, protection Structural support
Concrete internal columns, floors, walls	Fire barrier Heat sink Structural support
Fire rated doors	Fire barrier
Miscellaneous structural components	Flood barrier Missile barrier Structural support
Structural bolting	Structural support

2.4.3. Control Building Structure

Description

The Control Building (CB) is a rectangular, safety related, seismic Class I structure that is constructed from reinforced concrete with internal bracing provided by reinforced concrete walls, columns, and floors. The CB is adjacent to the Primary Auxiliary Building and enveloped by the Unit 1 and Unit 2 Turbine Buildings. The CB is enclosed within the Turbine Buildings but is an independent structure since it has no fixed structural attachments with either the Turbine Buildings or the Primary Auxiliary Building. The CB contains the Control Room, Computer Room, Control Room Ventilation Room, Cable Spreading Room, Vital and Non-Vital Switchgear Rooms, Battery Rooms, Auxiliary Feed Water Pumps, Train 'A' Emergency Diesel Generators, and air compressors. The CB also provides support for the Condensate Storage Tanks and operations offices. The CB structure consists of several areas on four levels, which are separated by reinforced concrete walls and floors or concrete masonry block walls. The building's basemat and foundation footings consist of reinforced concrete supported on compacted subgrade.

Boundary

The control building boundary includes all the structural components that comprise the control building. There are no significant differences between the SLR boundary and those identified as part of the original PBN license renewal.

Structure Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide structural support and housing to safety related SSCs.

Nonsafety-related that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide support to nonsafety-related SSCs such as flood barriers, HELB barriers, and Control Room habitability (accident radiation shielding and atmosphere control envelope).

Fire protection, Station Blackout (10 CFR 54.4(a)(3)):

(1) Provide structural support and housing to SSCs relied upon in safety analyses or plant evaluations that perform a function directly supporting the site's implementation of Fire Protection regulations.

(2) Provide structural support and housing to SSCs relied upon in safety analyses or plant evaluations that perform a function directly supporting the site's coping with a Station Blackout. The CB's Control Room and Computer Room reinforced concrete walls, floors and ceilings are credited as heat sinks.

UFSAR References

7.5.4
9.8
A.2.3

Subsequent License Renewal Drawing

The subsequent license renewal drawing for the control building is LR-C-3.

Components Subject to AMR

Table 2.4-3 lists the Control Building component types that require AMR and their associated component intended functions.

Table 3.5.2-3 provides the results of the Control Building AMR.

Table 2.4-3
Control Building Structure Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete basemat, foundation	Structural support
Concrete external walls and roof	Shelter, protection Structural support
Concrete interior walls, ceiling, floors	Fire barrier Flood barrier Heat sink HELB shielding Missile barrier Radiation shielding Shelter, protection Structural support
Door seals	Flood barrier
Fire rated doors	Fire barrier Flood barrier
Glass windows	HELB shielding Shelter, protection
Masonry (block) walls	Fire barrier Flood barrier Structural support
Miscellaneous structural components [2]	Flood barrier HELB shielding Missile barrier Structural support
Penetration Seals	Flood barrier Pressure boundary
Structural bolting	Structural support
Wooden beams	Missile barrier

2.4.4. Diesel Generator Building Structure

Description

The Diesel Generator Building (DGB) is a two-story rectangular, safety related, seismic Class I structure with an attached nonsafety-related, seismic Class III stairway-passageway enclosure along the building's west side. The building is an independent structure with no other buildings in its immediate vicinity. The safety related, seismic Class I portion of the DGB is constructed from reinforced concrete with internal bracing provided by reinforced concrete walls

[2] Miscellaneous structural components include barrier/shield bracing, damper housing/frame, drain covers and flanges, gratings, stairs, and platforms.

and floors. The DGB houses the Train 'B' Emergency Diesel Generators, including their support equipment and distribution switchgear, and the Fuel Oil Storage Tanks, and fuel oil transfer pumps that service all four Emergency Diesel Generators.

The seismic Class I part of the DGB consists of multiple compartments on two levels. The building's basemat and foundation footings consist of reinforced concrete supported on compacted subgrade. The building's highest level, the reinforced concrete roof is at elevation 66-feet (nominal). The building's nonsafety related seismic Class III stairway-passageway enclosure is constructed from structural steel and metal siding.

Boundary

The diesel generator building boundary includes all the structural components that comprise the diesel generator building. The differences between the current boundary and those identified as part of the original PBN license renewal are limited to joint and penetration seals conservatively included in the current boundary.

Structure Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide structural support and housing to safety related SSCs.

Nonsafety-related functions that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide support to nonsafety-related SSCs whose failure could adversely affect safety related functions.

Fire protection, Station Blackout functions (10 CFR 54.4(a)(3)):

(1) Provide structural support and housing to SSCs relied upon in safety analyses or plant evaluations that perform a function directly supporting the site’s implementation of Fire Protection regulation.

(2) Provide structural support and housing to SSCs relied upon in safety analyses or plant evaluations that perform a function directly supporting the site’s implementation of the Station Blackout regulation.

UFSAR References

8.8
A.5.9
D.2

Subsequent License Renewal Drawing

The subsequent license renewal drawing for the diesel generator building is LR-C-3.

Components Subject to AMR

Table 2.4-4 lists the Diesel Generator Building component types that require AMR and their associated component intended functions.

Table 3.5.2-4 provides the results of the AMR.

Table 2.4-4
Diesel Generating Building Structure Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete basemat, foundation	Structural support
Concrete external walls and roof	Flood barrier Missile barrier Shelter, protection Structural support
Concrete interior walls, ceiling, and floors	Flood barrier Missile barrier Shelter, protection Structural support
Fire rated doors	Fire barrier Structural support
Joint and penetration seals	Shelter, protection
Masonry (block) walls	Fire barrier Flood barrier Structural support
Miscellaneous structural components	Missile barrier Structural support Shelter, protection
Structural bolting	Structural support

2.4.5. Façade (Unit 1/2) Structure

Description

The Unit 1 and Unit 2 Façade Structures are seismic Class III structures consisting primarily of steel framing and metal siding. Each Façade's perimeter wall framing is supported vertically on reinforced concrete walls that are supported on an independent reinforced concrete foundation. The Façade structures have no intermediate floors other than a stair tower that provides access to upper elevations of the Primary Auxiliary Building and Containments. The Façades surround and enclose the reinforced concrete Containment structures and function primarily to provide the Containments protection from weather.

The top of each Façade Structures' foundation is at elevation 6-feet-6-inches. A reinforced concrete wall around the perimeter extends to elevation 31-feet. Structural steel framing with metal siding extend from the concrete walls to the roof, elevation 160-feet (nominal). Façade framing relies on lateral support from the Primary Auxiliary Building steel superstructure and the Containment building. Additionally, the Façade roof is partially supported by the

Containment concrete dome through steel base plates secured to the domes with anchor bolts and structural steel.

Boundary

Each Façade Structure boundary includes the structural components that comprise the Façade. The differences between the current boundary and those identified as part of the original PBN license renewal are limited to joint and penetration seals conservatively included in the current boundary.

Structure Intended Functions

Nonsafety-related functions that could affect safety-related functions (10 CFR 54.4(a)(2)):

1) Attached to and enclose the containment structures, and houses the reactor makeup water tank, as well as main steam and feedwater piping. The structures provide no physical protection from design basis external hazards. They provide weather protection for equipment and personnel and improve the architectural treatment of the plant.

UFSAR References

5.1
6.2
10.2
A.5

Subsequent License Renewal Drawing

The subsequent license renewal drawing for the façade structures is LR-C-3.

Components Subject to AMR

Table 2.4-5 lists the Façade Structures component types that require AMR and their associated component intended functions.

Table 3.5.2-5 provides the results of the AMR.

Table 2.4-5
Facade Unit 1/2 Structure Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete basemat, foundation	Structural support
Concrete exterior walls	Shelter, protection Structural support
Concrete interior walls	Shelter, protection Structural support
Masonry (block) walls	Shelter, protection Structural support
Structural steel and miscellaneous structural components	Structural support
Structural bolting	Structural support

2.4.6. Fuel Oil Pumphouse Structure

Description

The Fuel Oil Pumphouse (FOPH) Structure is a rectangular, safety related, seismic Class I structure constructed from reinforced concrete and concrete masonry block. This building is an independent structure with no other structures in its immediate vicinity. The FOPH building houses nonsafety-related mechanical and electrical equipment, including the Gas Turbine Fuel Oil Supply Pump, which is required for Gas Turbine Generator (G05) operation. G05 is relied upon as the Alternate AC (AAC) power source during a station blackout (SBO) and is relied upon to supply power to safe shutdown loads through the alternate shutdown equipment during a fire in 4160 V switchgear.

The FOPH Structure consists of several areas on two levels. Below grade, the building consists of reinforced concrete floor (basemat), walls, and ceiling. Above grade, the building is predominately concrete masonry block, except for the reinforced concrete floor and stairwell enclosure and the concrete slab roof. The building's basemat is at elevation 5-feet, the intermediate floor is at elevation 25-feet-6-inches, and the concrete roof is at elevation 35-feet-4-inches (nominal).

Boundary

The Fuel Oil Pumphouse Structure boundary includes all the structural components that comprise the Fuel Oil Pumphouse. The differences between the current boundary and those identified as part of the original PBN license renewal are limited to joint and penetration seals and above-grade masonry (block) conservatively included in the current boundary.

Structure Intended Functions

Fire protection, Station Blackout functions (10 CFR 54.4(a)(3)):

(1) Provide support and protection for the Gas Turbine Fuel Oil Supply Pump (P105) and associated components, which is required for G05

operation. G05 and the associated support equipment are relied upon in safety analyses and plant evaluations to support the site's ability to alternately power safe shutdown loads with a fire in the 4160 V switchgear.

(2) Provide support and protection for P105 and associated components, which is required for G05 operation. G05 and the associated support equipment are relied upon in safety analyses and plant evaluations to support the site's coping with a station blackout.

UFSAR References

8.9
A.5

Subsequent License Renewal Drawing

The subsequent license renewal drawing for the fuel oil pumphouse structure is LR-C-3.

Components Subject to AMR

Table 2.4-6 lists the Fuel Oil Pumphouse Structure component types that require AMR and their associated component intended functions.

Table 3.5.2-6 provides the results of the AMR.

Table 2.4-6
Fuel Oil Pumphouse Structure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete basemat, foundation	Structural support
Concrete exterior walls and roof	Flood barrier Missile barrier Shelter, protection Structural support
Concrete interior walls	Fire barrier Missile barrier Shelter, protection Structural support
Masonry (block) walls	Fire barrier Shelter, protection Structural support
Structural bolting	Structural support
Structural steel and miscellaneous structural components	Structural support

2.4.7. Gas Turbine Building Structure

Description

The Gas Turbine Building (GTB) Structure is a rectangular, nonsafety-related, seismic Class 3 structure that is constructed from prefabricated metal wall and roof panels attached to a structural steel frame. The building's structural steel frame is supported by a reinforced concrete basemat and foundation. The building is an independent structure with no other buildings in its immediate vicinity. The GTB houses nonsafety-related G05 and its associated mechanical and electrical equipment. G05 is relied upon as the AAC power source during an SBO and is relied upon to supply power to safe shutdown loads through the alternate shutdown equipment during a fire in 4160 V switchgear.

The GTB consists of a single compartment. The building's basemat, building elevation 0-feet-0-inches and foundation footings consist of reinforced concrete supported on compacted subgrade. Equipment foundations are integral with the building's basemat. The building's roof is at building elevation 16-feet-11-inches (nominal).

Boundary

The Gas Turbine Building Structure boundary includes all the structural components that comprise the Gas Turbine Building for operation of G05 and its associated electrical and mechanical equipment. The differences between the current boundary and those identified as part of the original PBN license renewal are that joint and penetration seals and miscellaneous structural components are conservatively included in the current boundary.

Structure Intended Functions

Fire protection, Station Blackout functions (10 CFR 54.4(a)(3)):

(1) Provide support and protection for the Gas Turbine Fuel Oil Supply Pump (P105), which is required for G05 operation. G05 and the associated support equipment are relied upon in safety analyses and plant evaluations to support the site’s ability to alternately power safe shutdown loads with a fire in the 4160 V switchgear.

(2) Provide support and protection for the P105, which is required for G05 operation. G05 and the associated support equipment are relied upon in safety analyses and plant evaluations to support the site’s coping with a station blackout.

UFSAR References

8.9
A.5

Subsequent License Renewal Drawing

The subsequent license renewal drawing for the gas turbine building structure is LR-C-3.

Components Subject to AMR

Table 2.4-7 lists the GTB Structure component types that require AMR and their associated component intended functions.

Table 3.5.2-7 provides the results of the AMR.

Table 2.4-7
Gas Turbine Building Structure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete basemat, foundation	Structural support
Concrete exterior walls	Flood barrier Missile barrier Shelter, protection Structural support
Concrete interior walls	Fire barrier Missile barrier Shelter, protection Structural support
Structural steel and miscellaneous structural components	Shelter, protection Structural support
Structural bolting	Structural support

2.4.8. Primary Auxiliary Building Structure

Description

The Primary Auxiliary Building (PAB) is a rectangular, multi-floored, reinforced concrete and steel framed structure consisting of a central area, and north and south wings. The PAB internal bracing is provided by reinforced concrete walls, floors, and slabs, and structural steel framing. The reinforced concrete PAB central area, and portions of the reinforced concrete north and south wings are seismic Class I structures. The PAB's steel superstructure is seismic Class III. Each PAB area is founded on its own basemat. The PAB's exterior is clad with metal wall panels. Four reinforced concrete pipeways extend from the PAB through the Facades to the Containments.

The PAB north wing structure, column lines 13 to 15 at elevations 8-feet and 26-feet, is seismic Class I. Also included in the review of the PAB is a portion of the South Service Building (SSB), a Class III structure. The SSB that extends from column line 5 to the north is within scope of license renewal. The PAB south wing structure, column lines 5 to 10 at elevation 8 feet and column lines 8 to 10 at elevation 26-feet, is seismic Class I. The PAB structure has basement floors at elevations (-)19-feet-3-inches and (-)5-feet-3-inches, a ground floor at elevation 8-feet, an intermediate floor at elevation 26-feet, and operating floors at elevations 46-feet, 52-feet, and 66-feet. The roof is at elevation 111-feet-9-inches (nominally). The Boiler Room and Water Treating areas located in the PAB north wing have a roof at elevation 52-feet.

Boundary

The Primary Auxiliary Building Structure boundary includes all the structural components that comprise the Primary Auxiliary Building. There are no significant differences between the current boundaries and those identified as part of the original PBN license renewal , other than addressing the spent fuel pool as a separate sub-structure.

Structure Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Structurally support and house safety related equipment.

Nonsafety-related functions that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Structurally supports and houses nonsafety-related equipment which can affect safety related equipment such as the Primary Auxiliary Building crane, HELB and flood doors, and spray shields.

Fire protection functions (10 CFR 54.4(a)(3)):

(1) Masonry block walls and fire doors within the Primary Auxiliary Building are relied upon for fire protection.

UFSAR References

1.3
6.2
A.5

Subsequent License Renewal Drawing

The subsequent license renewal drawing for the primary auxiliary building structure is LR-C-3.

Components Subject to AMR

Table 2.4-8 lists the Primary Auxiliary Building Structure component types that require AMR and their associated component intended functions.

Table 3.5.2-8 provides the results of the AMR.

Table 2.4-8
Primary Auxiliary Building Structure Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete basemat, foundation	Structural support
Concrete exterior walls and roof	Fire barrier Missile barrier Shelter, protection Structural support
Concrete interior walls, ceiling, and floors	Fire barrier Missile barrier Shelter, protection Structural support
Fire rated doors	Fire barrier Flood barrier
Masonry (block) walls	Fire barrier Structural support
Structural steel and miscellaneous structural components	Structural support Shelter, protection
New fuel storage racks	Structural support
Penetration seals	Flood barrier Fire barrier
Structural bolting	Structural support

2.4.9. Spent Fuel Pool and Transfer Canal

Description

The Spent Fuel Pool (SFP), a separate seismic Class I structure located within the central area of the PAB, is founded on its own basemat supported by steel H-piles driven to refusal into the bedrock. The SFP, including the transfer canal, is shared by the two units, and is kept full of water during and after the first refueling. In addition to new and used fuel storage racks, the SFP has an area set aside for accepting spent fuel shipping casks or dry storage casks. Cask loading is also done under water. Borated water is used to fill the spent fuel storage pool at a concentration to match or exceed that used in the reactor cavity and refueling canal during refueling operations.

The Boraflex associated with the fuel storage racks is no longer credited in the plant CLB with maintaining SFP subcriticality, as described in amendments 236 and 240 of the renewed operating licenses for PBN Unit 1 and Unit 2, respectively. As such, Boraflex no longer has an intend function for SLR and is not subject to AMR.

Boundary

The Spent Fuel Pool boundary includes all the structural components that comprise the Spent Fuel Pool and transfer canal. The refueling canal and transfer tube are located inside the containment and addressed in Section 2.4.1. The spent fuel pool is a sub-structure for and was addressed with the Primary Auxiliary Building Structure for the original PBN license renewal.

Structure Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Structurally support and house safety related SSCs.

UFSAR References

1.3
3.2
Figure 5.2-73-1
9.4
A.5

Subsequent License Renewal Drawing

The subsequent license renewal drawing for the primary auxiliary building structure, which includes the spent fuel pool is LR-C-3.

Components Subject to AMR

Table 2.4-9 lists the Spent Fuel Pool component types that require AMR and their associated component intended functions.

Table 3.5.2-9 provides the results of the AMR.

Table 2.4-9
Spent Fuel Pool Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete foundation	Structural support
Concrete spent fuel pool, transfer canal walls	Flood barrier Shelter, protection Structural support
H - piles	Structural support
Liner	Pressure boundary
Miscellaneous structural components	Structural support
Seals	Pressure boundary
Spent fuel pool upender	Structural support
Spent fuel storage racks	Structural support
Seals	Pressure boundary
Structural bolting	Structural support
Transfer canal gates	Pressure boundary

2.4.10. Turbine Building (Unit 1/2) Structure

Description

The Unit 1 and Unit 2 Turbine Buildings (TBs) are rectangular, nonsafety-related, seismic Class III structures that are constructed from structural steel and reinforced concrete with internal bracing provided by structural steel columns and beams. The TBs are adjacent to the Primary Auxiliary Building (PAB). The TBs are inline, with Unit 1 building being south of Unit 2 building and their Unit 1 to Unit 2 interface being over the Control Building (CB). The TBs enclose the CB, except for the CB's east and west walls. Lateral bracing exists between the TB's structural steel framing and the adjacent seismic Class III PAB's steel superstructure and South Service Building steel framing. The TBs have no fixed structural attachments with the adjacent seismic Class I structures, CB and PAB (lower reinforced concrete portion).

The TB basemats, elevation 8-feet, and foundation footings consist of reinforced concrete supported on compacted subgrade. The TB intermediate floors, at elevations 26-feet and 44-feet, consist of either reinforced concrete on metal decking or metal grating. The intermediate floors are supported by the buildings' structural steel columns and beams. The TB roofs, elevation 109-feet (nominal), are supported by interconnected structural steel trusses. The TB exterior consists primarily of metal wall panels.

Boundary

The Turbine Building Unit 1/2 Structure boundary includes all the structural components that comprise the Turbine Building. The differences between the current boundaries and those identified as part of the original PBN license renewal are that joint and penetration seals are conservatively included in the current boundary.

Structure Intended Functions

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide support to safety related and nonsafety-related SSCs, whose failure could adversely affect safety related functions. These TB SSCs include items such as the building’s support for the safety related Main Steam and Feedwater valves, overhead crane (NUREG-0612), Non-Vital Switchgear Area north wall HELB shield (Unit 2 only), and CR ventilation air intake ducting (Control Room habitability).

Fire protection functions (10 CFR 54.4(a)(3)):

(1) Contains SSCs relied upon in safety analyses or plant evaluations that perform a function directly supporting the site’s implementation of Fire Protection regulations.

UFSAR References

1.3
10.2
A.5
A.7

Subsequent License Renewal Drawing

The subsequent license renewal drawing for the turbine building structures is LR-C-3.

Components Subject to AMR

Table 2.4-10 lists the Turbine Building Structure component types that require AMR and their associated component intended functions.

Table 3.5.2-10 provides the results of the AMR.

Table 2.4-10
Turbine Building Structure Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete basemat, foundation	Structural support
Concrete exterior walls and roof	Structural support
Concrete interior walls and ceilings	Shelter, protection Structural support
Masonry (block) walls	Fire barrier Structural support
Structural steel and miscellaneous structural components	Structural support
Structural bolting	Structural support

2.4.11. Yard Structures

Description

Yard Structures includes electrical manholes and duct banks, tank foundations, SBO equipment foundations, tank and component foundations, block walls, and earthen berm barrier.

Electrical manholes and duct banks contain safety related and nonsafety-related cables. Manholes are a reinforced concrete box-type structure with a reinforced concrete or cast-iron cover. Duct banks are reinforced concrete structures that encase galvanized steel and PVC pipes which act as conduit for the electrical cables. In-scope SBO components include electrical distribution items needed for coping and power restoration. Typical yard structures are the equipment foundations, pads, and support structures. The gas turbine generator fuel oil tank foundations and surrounding earthen berm are also included.

Other miscellaneous yard structures, such as the sewer sub-system components (e.g., catch basins, head walls, manholes), road systems (e.g. parking lots, roads, curbs, sidewalks), fencing and gates, yard transformer and tower concrete foundations, lagoons and drainage ditches, concrete security barriers, utility poles, transformer fire walls, and lake bank stabilization materials (e.g., rip-rap), are not in the scope of subsequent license renewal.

Boundary

The yard structures boundary includes all the in-scope structural components that comprise the yard. There are no significant differences between the current boundaries and those identified as part of the original PBN license renewal effort, except for masonry walls that are conservatively included in the current boundary.

Structure Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Several electrical manholes and their associated duct banks contain safety related cables (those cables prefixed with a 'Z' or 'W'). Electrical systems and components vital to plant safety are designed as Class I, which provides suitable protection against severe external environmental phenomena.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide support to temporary flood barriers installed in the event of maximum wave run-up at maximum lake level.

Fire protection, Station Blackout functions (10 CFR 54.4(a)(3)):

(1) Support the ability of the Gas Turbine Generator (G05) to alternately power safe shutdown loads for fire scenarios in the Control Room, the Cable Spreading Room, or the Vital Switchgear Room. The fuel oil storage tank earthen berm confines flammable liquid.

(2) Directly support the ability of the Gas Turbine Generator (G05) to power safety related buses 1/2-A05 and 1/2-A06 through the onsite 13.8kV and 4160V electrical distribution systems. YARD assets also support offsite power restoration through portions of the offsite 345kV and the offsite 13.8kV electrical distribution systems. The Gas Turbine Generator (G05) and associated support equipment are relied upon in safety analyses and plant evaluations to support the site’s coping with a station blackout.

UFSAR References

1.3
2.5
2.6
2.8
8.0.1

Subsequent License Renewal Drawing

The subsequent license renewal drawings for the yard structures are LR-C-3; LR-E-100, Sheet 1, and LR-6704-E03401.

Components Subject to AMR

Table 2.4-11 lists the Yard Structures component types that require AMR and their associated component intended functions.

Table 3.5.2-11 provides the results of the AMR.

Table 2.4-11
Yard Structures Subject to Aging Management Review

Component Type	Component Intended Function(s)
Berm	Fire barrier
Concrete foundations (tanks and components)	Structural support
Concrete duct banks, manholes, trenches	Shelter, protection Structural support
Manholes	Fire barriers
Manway insulation boards	Structural support
Miscellaneous structural components	Fire Barrier Shelter, protection Structural Support
Structural bolting	Structural support

2.4.12. 13.8 kV Switchgear Building Structure

Description

The 13.8kV Switchgear Building Structure is a rectangular, nonsafety-related, seismic Class III, concrete and masonry block structure. The building is an independent structure with no other buildings in its immediate vicinity. The 13.8kV Switchgear Building Structure houses nonsafety-related electrical equipment, including 13.8kV Buses H01, H02, and H03 and 13.8kV Circuit Breakers H52-10, H52-20, H52-21, H52-30, and H52-31. The Gas Turbine Generator electrical power is supplied to the 13.8kV Power system via Circuit Breaker H52-10 and tie Bus H01. G05 is relied upon as the Alternate AC (AAC) power source during a station blackout (SBO) and is relied upon to supply power to safe shutdown loads through the alternate shutdown equipment during a fire in 4160 V switchgear.

The 13.8kV Switchgear Building Structure consists of a single level, which is divided into three separate rooms by 8-inch masonry block walls. The foundation consists of spread reinforced concrete footings and a reinforced concrete basemat that provides the operating floor at elevation 26-feet-6-inches. The building's perimeter walls are constructed of both poured reinforced concrete and masonry block. The roof is a concrete slab. The west wall (rear) and portions of the north and south walls of the building are set into an earthen embankment.

Boundary

The 13.8 kV Switchgear Building Structure boundary includes all the structural components that comprise the 13.8 kV Switchgear Building. The differences between the current boundary and those identified as part of the original PBN license renewal are the conservative inclusion of the roof, and miscellaneous structural components that are an integral part of the building's construction in the current boundary, along with joint and penetration seals that permit differential movement.

Structure Intended Functions

Fire protection, Station Blackout functions (10 CFR 54.4(a)(3)):

(1) Provide support and housing for SSCs that are relied upon in safety analyses and plant evaluations to support site's ability to alternately power safe shutdown loads with a fire in the 4160 V switchgear.

(2) Provide support and housing for SSC that are relied upon in safety analyses and plant evaluations to support the site's coping with a station blackout.

UFSAR References

8.2
8.9
A.1

Subsequent License Renewal Drawing

The subsequent license renewal drawing for the 13.8kV switchgear building structures is LR-C-3.

Components Subject to AMR

Table 2.4-12 lists the 13.8kV Switchgear Building Structure component types that require AMR and their associated component intended functions.

Table 3.5.2-12 provides the results of the AMR.

Table 2.4-12
13.8 kV Switchgear Building Structure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete basemat, foundation	Structural support
Concrete exterior walls and roof	Shelter, protection Structural support
Masonry (block) walls	Structural support
Structural bolting	Structural support
Structural steel and miscellaneous structural components	Structural support

2.4.13. Component Support Commodity

Description

The Component Support (CSUP) commodity contains component and equipment supports, pipe restraints, electrical raceways, and electrical enclosures associated with Unit 1, Unit 2, and Common plant systems and equipment. This commodity group includes the grout under the baseplate and fasteners used with the support or equipment anchorage.

Generally, supports provide the connection between a system's equipment or component and a plant structural member (e.g., wall, floor, ceiling, column, beam). They provide support for distributed loads (e.g., piping, tubing, HVAC ducting, conduit, cable trays) and localized loads (e.g., individual equipment). Specific types of equipment and components evaluated as part of this commodity group include:

- Raceways - Generic component type that is designed specifically for holding electrical wires and cables, such as cable trays, exposed and concealed metallic conduit or wireways. Commodity assets for raceways include both the component and the component's support and attachment. Underground ducts, a type of raceway, are included with Yard Structures.

- Electrical Enclosures - Generic component type that contains electrical components such as panels, boxes, cabinets, consoles, and bus ducts. An electrical enclosure includes both the enclosure and its supports and attachments.

- Pipe Supports - Includes all items used to support piping. The support boundary includes all the auxiliary steel and fasteners back to the structure's surface.

- Pipe Restraints - Failure and seismic restraints that limit pipe movement during postulated events. Includes structural steel and fasteners (e.g., bolts, studs, nuts).

- Equipment Supports - Includes structural steel, fasteners (e.g., bolts, studs, nuts), and vibration mounts (isolation elements) that secure equipment to structures. Supports for RCS Class 1 components (RCS Class 1 supports) are addressed in Section 2.4.1.

- HVAC Duct Supports - Includes structural steel and fasteners (e.g., bolts, studs, nuts) that support/attach ventilation duct to structures.

The CSUP commodity for SLR also includes insulation and insulation jacketing that surround various mechanical components, whereas insulation is integral to the electrical commodities addressed in Section 2.5.

The CSUP commodity excludes jet impingement barriers (e.g., High Energy Line Break barriers), and miscellaneous plant structures and their details (e.g., stairs, platforms, crane rails). These items were evaluated with the structure where they are located.

Boundary

The CSUP boundary includes all the structural components that comprise the CSUP commodity. The differences between the current boundaries and those identified as part of the original PBN license renewal effort are the conservative inclusion of insulation/jacketing in the current boundary.

Commodity Intended Functions

Safety-related functions (10 CFR 54.4(a)(1)):

(1) Provide structural support for safety related SSCs.

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) Provide structural support for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of station blackout, fire protection, or safety related functions.

Fire protection, Environmental Qualification, Anticipated Transient without Scram, Station Blackout functions (10 CFR 54.4(a)(3)):

(1) Provide support for SSCs that are relied upon in safety analyses and plant evaluations to support site's implementation of Fire Protection regulations.

(2) Provide support for environmentally qualified SSCs.

(3) Provide support for SSCs that are relied upon in safety analyses and plant evaluations to support site's implementation of Anticipated Transient without Scram regulations.

(4) Provide support for SSC that are relied upon in safety analyses and plant evaluations to support the site's coping with a station blackout.

UFSAR References

1.2

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-13 lists the Component Support Commodity component types that require AMR and their associated component intended functions.

Table 3.5.2-13 provides the results of the AMR.

Table 2.4-13
Component Supports Commodity Group Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage / embedment	Structural support
ASME Class 2 and 3 supports	Pipe whip restraint Structural support
ASME Class 2 and 3 structural bolting	Structural support
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support
Component supports	Structural support
Electrical enclosures - panels, boxes, cabinets, consoles	Shelter, protection Structural support
High-strength structural bolting	Structural support
Insulation	Insulation jacket integrity
Pipe restraints and HVAC duct supports	Pipe whip restraint Structural support
Structural bolting	Structural support
Vibration isolation elements	Structural support

2.4.14. Fire Barrier Commodity

Description

The Fire Barrier commodity includes all fire stops and fire wraps used throughout the site that are credited in the Fire Protection Program Design Document. Fire stops are the fire barrier penetration seals and cable tray fire stops. Fire wraps are an envelope system installed around electrical components, conduits, and cabling to maintain safe shutdown functions free of fire damage. In addition, structural steel member fire proofing would be considered a fire wrap.

Fire stops provide a fire resistance equivalent to the rating of the fire barrier in order to prevent the spreading of fire to adjacent fire areas or fire zones. Penetration seals are used to close openings in ceilings, floors, and walls. These openings may be electrical (e.g., cables, cable trays, conduits) or mechanical penetrations (e.g., pipes, instrument lines, ventilation ducts). Cable tray fire stops are a type of barrier that prevents the propagation of fire along the length of cables. Fire wrap is used to fulfill separation requirements between electrical trains when physical separation is restricted by spatial design considerations.

Fire doors, curbs, dikes, structural fire proofing, and hollow concrete block walls are evaluated as part of the structure where they are located. Fire damper and louver housings (e.g., through-wall and in-duct) are included here (scoped and screened independently). Fire detection and alarm (e.g., smoke detectors), and fire suppression (e.g., automatic sprinklers, automatic halon systems) are evaluated in the Fire Protection system in Section 2.3.3.6.

Boundary

The Fire Barrier commodity boundary includes all the structural components that comprise the Fire Barrier commodity. There are no significant differences between the current boundaries and those identified as part of the original PBN license renewal.

Commodity Intended Functions

Fire protection functions (10 CFR 54.4(a)(3)):

(1) Fire Areas and their boundaries have been identified and analyzed and determined to provide sufficient protection to prevent the spread of a fire beyond the boundaries.

UFSAR References

9.10

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-14 lists the Fire Barrier Commodity component types that require AMR and their associated component intended functions.

Table 3.5.2-14 provides the results of the AMR.

Table 2.4-14
Fire Barrier Commodity Group Subject to Aging Management Review

Component Type	Component Intended Function(s)
Fire barrier penetration seals	Fire barrier
Fire damper and louver frames	Fire barrier
Fireproofing	Fire barrier
Fire stops and wraps	Fire barrier

2.4.15. Cranes, Hoists, and Lifting Devices

Description

The Cranes, Hoists, and Lifting Devices system consists of fuel handling cranes and load handling systems that comply with NUREG-0612. The fuel handling cranes include the reactor cavity manipulator cranes and the SFP bridge crane. Fuel handling cranes are not within the scope of subsequent license renewal for they have no intended function, i.e., they are not safety related or heavy load capacity. Furthermore, as described in response to RAI 2.4-9 and NUREG-1839 for the current renewed licenses, the manipulator crane and SFP crane do not have the potential to impact safety related components during normal plant operation. In addition, the potential radiological consequences for the postulated fuel handling accident as described in UFSAR Chapter 14.2.1 are well within the dose guidelines of 10 CFR 100.

The NUREG-0612 load handling systems include the Containment Cranes, the Auxiliary Building Main Crane, and the Turbine Building Overhead Crane. This system also includes the Emergency Diesel Generator G03 and G04 Cranes and Monorails (Diesel Generator Building), the RCP Motor Lifting Devices, and the Reactor Vessel Head and Internals Lifting Rigs. The specific components comprising this system are the structural members (bridge and trolley) of these heavy load cranes and lifting devices, including the crane rails and hardware.

These load-handling systems were identified to have the potential for a heavy load drop, which could result in damage to safe shutdown equipment. The remainder of the cranes, hoists, and lifting devices are excluded due to their load carrying capacity (being less than that of a heavy load) or their lack of proximity to safe shutdown equipment.

Boundary

The Cranes, Hoists, and Lifting Devices boundary includes all the structural components that comprise the Cranes, Hoists, and Lifting Devices that meet NUREG-0612. The boundary is limited to the load-bearing components that structurally support the heavy loads in a passive manner. This includes the bridge and trolley items such as structural beams, girders, and rails. There are no significant differences between the current boundary and those identified as part of the original PBN license renewal.

System Intended Functions

Nonsafety-related components that could affect safety-related functions (10 CFR 54.4(a)(2)):

(1) By definition of NUREG 0612, the safe handling of heavy loads is a nonsafety affecting safety function or the load handing systems are required to meet single failure proof criteria.

UFSAR References

A.3

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-15 lists the Cranes, Hoists, and Lifting Devices component types that require AMR and their associated component intended functions.

Table 3.5.2-15 provides the results of the AMR.

Table 2.4-15
Cranes, Hoists, and Lifting Devices Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bridge and Trolley Framing	Structural support
Crane Rails	Structural support
Lifting Devices	Structural support
Monorails	Structural support
Rail Hardware	Structural support

2.5. SCOPING AND SCREENING RESULTS: ELECTRICAL AND INSTRUMENTATION AND CONTROLS

The determination of electrical systems that fall within the scope of subsequent license renewal is made through the application of the process described in Section 2.1. The results of the electrical systems scoping review are contained in Section 2.2.

The methodology used in identifying electrical and I&C components requiring an AMR is discussed in Section 2.1.5.3. The screening for electrical and I&C components was performed on a generic component commodity group basis for the in-scope PBN systems, structures and commodity groups evaluated in Table 2.2-1. The methodology employed is consistent with the guidance in NEI 17-01.

The interface of electrical and I&C components with other types of components and the assessments of these interfacing components are provided in the appropriate mechanical or structural sections. For example, the assessment of electrical racks, panels, frames, cabinets, cable trays, conduits, and their supports is provided in the structural assessment documented in Sections 2.4 and 3.5.

The electrical and I&C components included in the screening were the separate electrical and I&C components that were not parts of larger components. For example, the wiring, terminal blocks, and connections located internal to a breaker cubicle were considered to be parts of the breaker. Accordingly, the breaker was screened, but not the internal parts of the breaker.

2.5.1. Electrical and I&C Component Commodity Groups

2.5.1.1. Identification of Electrical and I&C Components

The electrical and I&C component commodity groups were identified from a review of electrical systems within the scope of 10 CFR 54, controlled electrical drawings, NAMS, and interface with parallel mechanical and structural screening efforts. This commodity based approach, whereby component types with similar design and/or functional characteristics are grouped together, is consistent with guidance from NEI 17-01 and Table 2.1-6 of NUREG-2192. The in-scope electrical and I&C component commodity groups identified at PBN Units 1 and 2 are listed in Table 2.5-1.

2.5.1.2. Application of Screening Criterion 10 CFR 54.21(a)(1)(i) to the Electrical and I&C Components and Commodities

Following the identification of the electrical components and commodity groups, the criterion of 10 CFR 54.21(a)(1)(i) is applied to identify electrical commodity groups that perform their functions without moving parts or without a change in configuration or properties. The following electrical commodity groups meet the screening criteria of 10 CFR 54.21(a)(1)(i) for PBN:

- Insulated cables and connections
- Electrical and I&C penetration assemblies
- Metal Enclosed Bus
- High voltage insulators
- Switchyard bus
- Transmission conductors
- Uninsulated ground conductors

2.5.1.3. Elimination of Electrical and I&C Commodity Groups Not Applicable to PBN

The following electrical and I&C commodity groups are not applicable to PBN:

<u>Cable Tie-Wraps</u>

At PBN, cable fasteners and tie-wraps are intended to be used for training cables, assembling wires or cables into neat bundles and for general housekeeping purposes. They are not considered a cable support. Electrical cable tie-wraps do not function as cable supports in raceway support analyses; therefore, the installation and inspection criteria is limited to the application of standard practices in providing quality cable bundles and cable placement. Seismic qualification of cable trays does not credit the use of electrical cable tie-wraps. Cable tie-wraps have no SLR intended functions as defined in 10 CFR 54.4(a). Since cable tie-wraps do not have a SLR intended function, they are not subject to an AMR.

<u>Cable Bus</u>

Cable bus is a variation of metal enclosed bus which is similar in construction to a metal enclosed bus, but instead of segregated or nonsegregated electrical buses, cable bus is comprised of a fully enclosed metal enclosure that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus may omit the top cover or use a louvered top cover and enclosure. Both the cable bus and enclosures are not sealed against intrusion of dust, industrial pollution, moisture, rain, ice and, therefore, may introduce debris into the internal cable bus assembly. Cable bus is not utilized at PBN. Accordingly, cable bus is not subject to an AMR.

<u>Fuse Holders (Metallic Clamps)</u>

The cables and connections commodity group includes fuse holders (fuse blocks). Consistent with NUREG-2191, XI.E5, *Fuse Holders,* the screening of fuse holders (metallic clamps) applies to those that are not part of a larger (active) assembly. Fuse holders inside the enclosure of an active component, such as switchgear, power supplies, power inverters, battery chargers, and circuit boards are considered piece parts of the larger assembly. Since piece parts and subcomponents in such an enclosure are routinely inspected and regularly maintained as part of the plant's normal maintenance and surveillance activities, they are not subject to an AMR.

For original License Renewal, PBN determined aging management of fuse holders would be required for those cases where fuse holders are not considered subcomponent parts of a larger assembly. However, no fuse holders were identified at PBN that are located outside of a larger active component and thus no separate aging management program was proposed for fuse holders. Prior to entering into the first period of extended operation (PEO), PBN conducted a readiness assessment by performing a gap analysis with respect to fuse holders (NUREG-1801, Revision 2, Section XI.E5). This assessment is documented in the corrective action system. The gap analysis concluded PBN had not identified any fuse holders outside the enclosure of an active component that require aging management.

To validate that no fuse holders at PBN are located outside of a larger active component for SLR, a two (2) part site evaluation was performed. First, an evaluation of the sites engineering change (EC) process was undertaken and it was concluded PBN had not identified any fuse holders outside the enclosure of an active component that require aging management under the EC process. Second, a plant equipment database query from 2010 to January 2020 was developed to confirm the results of the EC process evaluation. The results of the equipment database evaluation confirmed (consistent with the EC process evaluation) there are no fuses that support a system level intended function that are not part of an active component such as switchgear, power supplies, power inverters, battery chargers, load centers, and circuit boards. It is concluded that fuses, including metallic clamps for the fuse clips of the fuse holders are considered piece parts of a larger assembly and are thereby not subject to an AMR.

Uninsulated Ground Conductors

Uninsulated ground conductors are electrical conductors (e.g., copper cable, copper bar) that are uninsulated (bare) and are used to make ground connections for electrical equipment. Uninsulated ground conductors are connected to electrical equipment housings and electrical enclosures as well as metal structural features such as the cable tray system and building structural steel. Uninsulated ground conductors are connected by compression or fusion (soldered or welded) connections to interfacing equipment. Compression and fusion connections involve various types of metals and other inorganic materials that have no aging effects that would result in loss of intended function.

Uninsulated ground conductors enhance the capability of the electrical system to withstand electrical system disturbances (e.g., electrical faults, lightning surges) for equipment and provide personnel protection. Uninsulated ground conductors are always isolated or insulated from the electrical operating circuits and are not required for those circuits or equipment to perform their intended functions. Uninsulated ground conductors are not mentioned in the FSAR nor used in the PRA analysis for plant safety evaluations. Therefore, uninsulated ground conductors are not within the scope of SLR for PBN.

2.5.1.4. Application of Screening Criteria 10 CFR 54.21(a)(1)(ii) to Electrical and I&C Commodity Groups

The 10 CFR 54.21(a)(1)(ii) screening criterion was applied to the specific commodities that remained following application of the 10 CFR 54.21(a)(1)(i) criterion. Criterion 10 CFR 54.21(a)(1)(ii) allows the exclusion of those commodities that are subject to replacement based on a qualified life or specified time period. The only electrical commodities identified for exclusion by the criteria of 10 CFR 54.21(a)(1)(ii) are electrical and I&C components and commodities included in the EQ Program. This is because electrical and I&C components and commodities included in the EQ Program have defined qualified lives and are replaced prior to the expiration of their qualified lives. No electrical and I&C components and commodities within the EQ Program are subject to AMR in accordance with the screening criterion of 10 CFR 54.21(a)(1)(ii). Note that TLAAs associated with electrical and I&C components within the EQ Program are discussed in Section 4.4.

Insulated Cables and Connections

The function of insulated cables and connections is to electrically connect specified sections of an electrical circuit to deliver voltage, current, or signals. Electrical cables and their required terminations (i.e., connections) are reviewed as a single component commodity group. The types of connections included in this review are splices, connectors, and terminal blocks. Numerous insulated cables and connections are included in the EQ Program. The insulated cables and connections that are included in this program have a qualified life that is documented in the EQ Program. Components in the EQ Program are replaced prior to the expiration of their qualified life. Accordingly, all insulated cables and connections within the EQ Program are replacement items under 10 CFR 54.21(a)(1)(ii) and are not subject to an AMR. Note that TLAAs associated with electrical/I&C components within the EQ Program are discussed in Section 4.4.

Insulated cables and connections that perform an intended function within the scope of SLR, but are not included in the EQ Program, meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

Switchyard Bus, High Voltage Insulators, Transmission Conductors

NUREG-2191, Chapter VI.A, addresses components that are relied upon to meet the SBO requirements for restoration of offsite power. This guidance is consistent with the guidance provided to the original license renewal applicants under NRC letter dated April 1, 2002. An evaluation was performed as part of the original PBN license renewal effort to determine the restoration power path for offsite power following an SBO event based on the guidance of the NRC letter. Consistent with the evaluation performed for the original PBN license renewal application used for the first period of extended operation, the switchyard commodities of switchyard bus, high-voltage insulators, transmission conductors, and metal enclosed bus perform an intended function for restoration of offsite power following an SBO event. Additionally, none of these commodities are included in the EQ Program. Thus, these commodities meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

The electrical interconnection between PBN Units 1 and 2 and the offsite transmission network and the off-site power recovery paths following an SBO are highlighted on electrical boundary drawing SLR-ELECTRICAL-E1.

Electrical and I&C Penetration Assemblies

There are fifty-eight (58) electrical penetration assemblies per unit installed at PBN consisting of three types. Electrical and I&C penetration assemblies included in the EQ Program have a qualified life that is documented. Therefore, electrical and I&C penetration assemblies in the EQ Program do not meet the criterion of 10 CFR 54.21(a)(1)(ii) and are not subject to an AMR.

Electrical and I&C penetration assemblies that are within the scope of SLR, but not included in the EQ Program, meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

Metal Enclosed Bus

Metal enclosed bus (MEB) is used to connect two or more elements (i.e., electrical equipment such as switchgear and transformers) of an electrical circuit. This commodity group includes three broad categories of MEB; isolated (iso) phase bus, non-segregated phase bus, and segregated phase bus. Iso-phase bus is electrical bus in which each phase conductor is enclosed by an individual metal housing separated from adjacent conductor housings by an air space. Non-segregated phase bus is electrical bus constructed with all phase conductors in a common enclosure without barriers (only air space) between the phases. Segregated phase bus is electrical bus constructed with all phase conductors in a common enclosure but segregated by metal barriers between phases. Segregated phase bus is not utilized at PBN and the iso-phase bus does not perform or support a SLR intended function. Only non-segregated MEB in the 13.8kV, 4.16 kV and 480V systems perform a SLR intended function and none of this MEB is in the EQ Program. Therefore, non-segregated MEB in the 13.8kV, 4.16 kV and 480V systems meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

2.5.2. Electrical and I&C Commodity Groups Subject to Aging Management Review

Table 2.5-2 lists the electrical and I&C commodity groups that require AMR and their associated component intended functions.

Table 3.6.2-1 provides the results of the AMR.

Table 2.5-1
Electrical and I&C Component Commodity Groups Installed at PBN for In-Scope Systems

Alarm Units	Electrical/I&C Penetration Assemblies	Light Bulbs	Solenoid Operators
Analyzers		Load Centers	Signal Conditioners
		Loop Controllers	Solid-State Devices
Annunciators	Elements	Meters	Splices
Batteries	Fuses	Motor Control Centers	Surge Arresters
Chargers	Generators	Motors	Switches
Circuit Breakers	Heat Tracing	Power Distribution Panels	Switchgear
Converters	Electric Heaters	Power Supplies	Switchyard Bus
Communication Equipment	High-Voltage Insulators	Radiation Monitors	Terminal Blocks
Electrical Bus (aka Metal Enclosed Bus)	Indicators	Recorders	Thermocouples
	Cables and Connections	Regulators	Transducers
Electrical Controls and Panel Internal Component Assemblies		Relays	Transformers
	Inverters	RTDs	Transmitters
	Isolators	Sensors	Transmission Conductors
			Uninsulated Ground Conductors

Table 2.5-2
Electrical and Instrumentation and Control Systems Components Subject to Aging Management Review

Structure and/or Component/ Commodity	Component Intended Function(s)
Non-EQ Insulated Cables and Connections	Electrical continuity
Non-EQ Electrical/I&C Penetration Assemblies	Electrical continuity
Metal Enclosed Bus-conductors Metal Enclosed Bus-insulators (Includes sections used for SBO recovery)	Electrical continuity Insulate (electrical)
High-Voltage Insulators (for SBO recovery)	Insulate (electrical)
Switchyard Bus and Connections (for SBO recovery)	Electrical continuity
Transmission Conductors and Connections (for SBO recovery)	Electrical continuity

3.0 AGING MANAGEMENT REVIEW RESULTS

This chapter provides the results of the AMR for those systems and structures in the scope of SLR as shown in Table 2.2-1. Organization of this chapter is based on Tables 3.1-1 through 3.6-1 of NUREG-2192, “Standard Review Plan for the Review of Subsequent License Renewal Applications for Nuclear Power Plants”.

The major sections of this chapter are:

- Aging Management of Reactor Vessel, Internals, and Reactor Coolant System (Section 3.1)
- Aging Management of Engineered Safety Features (Section 3.2)
- Aging Management of Auxiliary Systems (Section 3.3)
- Aging Management of Steam and Power Conversion Systems (Section 3.4)
- Aging Management of Containments, Structures, and Component Supports (Section 3.5)
- Aging Management of Electrical and Instrumentation and Controls (Section 3.6)

Descriptions of the service environments that were used in the mechanical systems AMR to determine aging effects requiring management are included in Table 3.0-1, Mechanical System Service Environments. The environments used in the AMRs are listed in the Environment column. The third column identifies one or more of the NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report,” environments that were used when comparing the PBN AMR results to the NUREG-2191 results. Structural service environments are in Table 3.0-2 and electrical service environments are in Table 3.0-3. The definitions of those environments correspond to the definitions in NUREG-2191, Section IX.D.

The remaining AMR results information in Section 3 is presented in the following two tables:

Table 3.x.1 - where '3' indicates the SLRA Section number, 'x' indicates the subsection number from NUREG-2191, and '1' indicates that this is the first Table type in Section 3. For example, in the Reactor Vessel, Internals, and Reactor Coolant system subsection, this Table would be number 3.1.1, in the Engineered Safety Features subsection, this Table would be 3.2.1, and so on. For ease of discussion, this Table will, hereafter, be referred to in this Section as “Table 1.”

Table 3.x.2-y - where '3' indicates the SLRA Section number, 'x' indicates the subsection number from NUREG-2191, and '2' indicates that this is the second Table type in Section 3; and 'y' indicates the Table number for a specific system. For example, for the reactor vessel, within the Reactor Vessel, Internals, and Reactor Coolant system subsection, this Table would be 3.1.2-1 and for the reactor vessel internals, it would be Table 3.1.2-2. For the containment spray system, within the Engineered Safety Features subsection, this Table would be 3.2.2-1. For the next system within the Engineered Safety Features subsection, it would be Table 3.2.2-2. For ease of discussion, this Table will, hereafter, be referred to in this section as “Table 2."

Table Description

Table 1

The purpose of Table 1 is to provide a summary comparison of how the facility aligns with the corresponding tables of NUREG-2192. The Table is essentially the same as Tables 3.1-1 through 3.6-1 provided in NUREG-2192, except that the "New, Modified, Deleted, Edited Item," "ID" and "Type" columns have been replaced by an "Item Number" column, and the "GALL-SLR Item" column has been replaced by a "Discussion" column.

The "Item Number" column provides the reviewer with a means to cross-reference from Table 2 to Table 1.

The "Discussion" column is used to provide clarifying or amplifying information. The following are examples of information that might be contained within this column:

- "Further Evaluation Recommended" information or reference to where that information is located
- The name of a plant specific aging management program being used, if applicable
- Exceptions to the NUREG-2191 assumptions, if applicable
- A discussion of how the line is consistent with the corresponding line item in NUREG-2191, when that may not be intuitively obvious
- A discussion of how the item is different than the corresponding line item in NUREG-2191 when it may appear to be consistent (e.g., when there is exception taken to an aging management program that is listed in NUREG-2191), if applicable

The format of Table 1 provides the reviewer with a means of aligning a specific Table 1 row with the corresponding NUREG-2192 Table row, thereby allowing for the ease of checking consistency.

Table 2

Table 2 provides the detailed results of the AMRs for those components identified in SLRA Section 2 as being subject to AMR. There is a Table 2 for each of the systems within a Chapter 3 Section grouping. For example, the Engineered Safety Features subsection group contains tables specific to the safety injection system, containment spray system, residual heat removal system, and containment isolation components system. Table 2 consists of the following nine columns:

- Component Type
- Intended Function
- Material
- Environment
- Aging Effect Requiring Management
- Aging Management Programs
- NUREG-2191 Item

- Table 1 Item
- Notes

Component Type - The first column identifies all of the component types from Section 2 of the SLRA that are subject to AMR. They are listed in alphabetical order.

Intended Function - The second column contains the subsequent license renewal intended functions for the listed component types. Definitions of intended functions are contained in Table 2.1.5-1.

Material - The third column lists the particular materials of construction for the component type.

Environment - The fourth column lists the environments to which the component types are exposed. Service environments are indicated and a list of mechanical system service environments is provided in Table 3.0-1. The Structural and Electrical AMRs use environment names consistent with the assigned NUREG-2191 items and shown in Table 3.0-2 and Table 3.0-3, respectively. The definitions of those environments correspond to the definitions in NUREG-2191, Section IX.D.

Aging Effect Requiring Management - As part of the AMR process, the aging effects that are required to be managed in order to maintain the intended function of the component type are identified for the material and environment combination. These aging effects requiring management are listed in the fifth column.

Aging Management Programs - The aging management programs used to manage the aging effects requiring management are listed in the sixth column of Table 2. Aging management programs are described in Appendix B.

NUREG-2191 Item - Each combination of component type, material, environment, aging effect requiring management, and aging management program that is listed in Table 2, is compared to NUREG-2191, with consideration given to the standard notes, to identify consistency. Consistency is documented by noting the appropriate NUREG-2191 item number in the seventh column of Table 2. If there is no corresponding item number in NUREG-2191, this field in column seven is marked “None.” Thus, a reviewer can readily identify the correlation between the plant-specific tables and the NUREG-2191 tables.

Table 1 Item - Each combination of component, material, environment, aging effect requiring management, and aging management program that has an identified NUREG-2191 item number must also have a Table 3.x.1 line item reference number. The corresponding line item from Table 1 is listed in the eighth column of Table 2. If there is no corresponding item in NUREG-2191, this field in column eight is marked “None.” The Table 1 Item allows correlation of the information from the two tables.

Notes - The notes provided in each Table 2 describe how the information in the Table aligns with the information in NUREG-2191. Each Table 2 contains standard industry lettered notes and, if applicable, plant-specific numbered notes. The standard industry lettered notes (e.g., A, B, C) provide standard information regarding comparison of the AMR results with the NUREG-2191 Aging Management Table line item identified in the seventh column. In addition to the standard industry lettered notes, numbered plant-specific notes provide additional clarifying information when appropriate.

Table Usage

Table 1

The reviewer evaluates each row in Table 1 by moving from left to right across the table. Since the Component, Aging Effect, Aging Management Programs and Further Evaluation Recommended information is taken directly from NUREG-2192, no further analysis of those columns is required.

The information intended to help the reviewer in this table is contained within the Discussion column. Here the reviewer will be given plant-specific information necessary to determine, in summary, how the evaluations and programs align with NUREG-2191. This may be in the form of descriptive information within the Discussion column or the reviewer may be referred to other locations within the SLRA for further information. A statement of "Consistent with NUREG-2191" means that the Table 2 items that link to that Table 1 row are consistent with the material, environment, aging effect, and program(s) associated with the assigned NUREG-2191 row, followed by any clarifications or exceptions that may apply.

Table 2

Table 2 contains all of the AMR information for the plant, whether or not it aligns with NUREG-2191. For a given row within the table, the reviewer is able to see the intended function, material, environment, aging effect requiring management and aging management program combination for a particular component type within a system. Within each system or structure, the intended functions for each component type are consolidated for Table listing. In addition, if there is a correlation between the combination in Table 2 and a combination in NUREG-2191, this will be identified by a referenced item number in column seven, NUREG-2191 Item. The reviewer can refer to the item number in NUREG-2191, if desired, to verify the correlation. If the column contains "None," no corresponding combination in NUREG-2191 was found. As the reviewer continues across the Table from left to right, within a given row, the next column is labeled Table 1 Item. If there is a reference number in this column, the reviewer is able to use that reference number to locate the corresponding row in Table 1 and see how the aging management program for this particular combination aligns with NUREG-2191.

Table 2 provides the reviewer with a means to navigate from the components subject to AMR in SLRA Section 2 all the way through the evaluation of the programs that will be used to manage the effects of aging of those components.

Table 3.0-1
Mechanical System Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
Air – dry	Air that has been treated to reduce its dew point well below the system operating temperature and treated to control lubricant content, particulate matter, and other corrosive contaminants.	Air – dry
Air – indoor controlled	An environment where the specified internal or external surface of the component or structure is exposed to a humidity-controlled (i.e., air conditioned) environment.	Air – indoor controlled
Air – indoor uncontrolled	This environment is for indoor locations that are sheltered/protected from weather. Surfaces of components in this environment may also be periodically exposed to condensation.	Air – indoor uncontrolled
Air – outdoor	The outdoor environment consists of atmospheric air, salt-laden air, ambient temperature and humidity, and exposure to precipitation. Surfaces of components in this environment may also be periodically exposed to condensation.	Air – outdoor
Air with borated water leakage	This environment is similar to the Air-indoor uncontrolled environment but is used for components located within buildings that have systems containing treated borated water as they may be susceptible to borated water leakage and subsequent boric acid corrosion.	Air with borated water leakage
Concrete	Components in contact with concrete.	Concrete
Condensation	This environment is applied to the internal unsubmerged surfaces of the pressurizer relief tank that are subject to periodic wetting. The environment of “Air – indoor uncontrolled” or “Air – outdoor” is used for other surfaces that may be periodically exposed to condensation.	Condensation
Diesel exhaust	Gases, fluids, particulates present in diesel engine exhaust.	Diesel exhaust
Fuel oil	Diesel oil, No. 2 oil, or other liquid hydrocarbons used to fuel diesel engines.	Fuel oil
Gas	Internal dry non-corrosive gas environment such as nitrogen, carbon dioxide, Freon, and halon.	Gas
Lubricating oil	Lubricating oils are low- to medium-viscosity hydrocarbons used for bearing, gear, and engine lubrication. An oil analysis program may be credited to preclude water contamination.	Lubricating oil

Table 3.0-1
Service Environments for Mechanical AMRs

Environment	Description	Corresponding NUREG-2191 Environments
Neutron flux	Neutron flux integrated over time. Neutron fluence is specified as an environment for the limiting reactor vessel components with material properties that may be significantly affected by neutron irradiation.	Neutron flux High fluence ($>1 \times 10^{17}$ n/cm^2, E > 0.1 million electron volts [MeV])
Raw water	Water that enters the plant from the cooling water canals, ocean, bay, or city water source that has not been demineralized. In general, the water has been rough filtered to remove large particles and may contain a biocide for control of microorganisms and macro-organisms. Although city water is purified for drinking purposes, it is conservatively classified as raw water for the purposes of AMR. As a note, the raw water in the cooling water canals has a higher saline content than local ocean or bay water.	Raw water
Reactor coolant	Reactor coolant is treated water in the reactor coolant system and connected systems at or near full operating temperature. This includes wet steam in the pressurizer.	Reactor coolant
Steam	Steam, subject to a water chemistry program. In determining aging effects, steam is considered treated water.	Steam
Soil	External environments included in the soil category consist of components at the air/soil interface, buried in the soil, or exposed to groundwater in the soil.	Soil
Treated borated water	Treated or demineralized borated water.	Treated borated water
Treated borated water >140°F	Treated or demineralized borated water above stress corrosion cracking (SCC) threshold for stainless steel.	Treated borated water >140°F
Treated water	Treated water is demineralized water and is the base water for all clean systems.	Treated water
Treated water >140°F	Treated water above 140°F SCC threshold for SS.	Treated water >140°F
Underground	Underground piping and tanks below grade but are contained within a tunnel or vault such that they are in contact with air and are located where access for inspection, is limited. When the underground environment is cited, the term includes exposure to air-outdoor, air-indoor uncontrolled, air, raw water, groundwater, and condensation.	Underground
Wastewater	Water in liquid waste drains such as in liquid radioactive waste, oily waste, floor drainage, chemical waste water, and secondary waste water systems. Waste waters may contain contaminants, including oil and boric acid, as well as treated water not monitored by a chemistry program.	Waste water

Table 3.0-2
Structural Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
Air – indoor controlled	An environment where the specified internal or external surface of the component or structure is exposed to a humidity-controlled (i.e., air conditioned) environment.	Air – indoor controlled
Air – outdoor	The outdoor environment consists of moist, possibly salt-laden air and spray, cooling tower plumes (which might contain chemical additives), industrial pollutants (e.g., fly ash, soot), ambient temperatures and humidity, and exposure to weather events, including precipitation and wind. The outdoor air environment also potentially includes component contamination due to animal infestation including by-products or excrement containing uric acid, ammonia, phosphates, or other compounds. The outdoor air environment can also result in submergence of components (particularly when they are in vaults) due to the potential for water to accumulate or due to external or internal buildup of condensation.	Air – outdoor
Air with borated water leakage	Air and untreated borated water leakage on indoor or outdoor systems with temperatures either above or below the dew point. The water from leakage is considered to be untreated, due to the potential for water contamination at the surface. Therefore, the systems may be susceptible to borated water leakage and subsequent boric acid corrosion.	Air with borated water leakage
Fuel oil	Diesel oil, No. 2 oil, or other liquid hydrocarbons used to fuel diesel engines.	Fuel oil
Soil	Soil is a mixture of inorganic materials produced by the weathering of rock and clay minerals, and organic material produced by the decomposition of vegetation. Voids containing air and moisture occupy 30–60% of the soil volume. Properties of soil that can affect degradation kinetics include moisture content, pH, ion exchange capacity, density, and hydraulic conductivity. External environments included in the soil category consist of components at the air/soil interface, buried in the soil, or exposed to groundwater in the soil. See also “groundwater/soil.”	Soil

Table 3.0-2
Structural Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
Treated borated water	Borated water is a controlled water system. The CV maintains the proper water chemistry in the reactor coolant system while adjusting the boron concentration during operation to match long-term reactivity changes in the core.	Treated borated water
Treated borated water >140°F	Treated or demineralized borated water above the stress corrosion cracking (SCC) (140ºF) threshold for stainless steel.	Treated borated water >140°F
Water - flowing	Water that is refreshed; thus, it has a greater impact on leaching and can include rainwater, raw water, groundwater, or water flowing under a foundation.	Water-flowing
Water - standing	Water that is stagnant and unrefreshed, thus possibly resulting in increased ionic strength up to saturation.	Water-standing

Table 3.0-3
Service Environments for Electrical AMRs

Environment	Description	Corresponding NUREG-2191 Environments
Air – indoor controlled	An environment where the specified internal or external surface of the component or structure is exposed to a humidity-controlled (i.e., air conditioned) environment. For electrical components and structures, the controlled environment must be sufficient to show that the electrical component(s) or structure(s) are not subjected to the cited aging effect(s) (e.g., reduced insulation resistance). The potential for leakage from bolted connections (e.g., flanges, packing) impacting in-scope components exists when citing the air–indoor controlled environment.	Air – indoor controlled
Air – indoor uncontrolled	Air–indoor uncontrolled is associated with systems with temperatures higher than the dew point (i.e., condensation can occur, but only rarely; equipment surfaces are normally dry). The potential for leakage from bolted connections (e.g., flanges, packing) impacting in-scope components exists in this environment.	Air – indoor uncontrolled
Air – outdoor	The outdoor environment consists of moist, possibly salt-laden air and spray, cooling tower plumes (which might contain chemical additives), industrial pollutants (e.g., fly ash, soot), ambient temperatures and humidity, and exposure to weather events, including precipitation and wind. The outdoor air environment also potentially includes component contamination due to animal infestation including by-products or excrement containing uric acid, ammonia, phosphates, or other compounds. The outdoor air environment can also result in submergence of components (particularly when they are in vaults) due to the potential for water to accumulate or due to external or internal buildup of condensation.	Air – outdoor
Air with borated water leakage	Air and untreated borated water leakage on indoor or outdoor systems with temperatures either above or below the dew point. The water from leakage is considered to be untreated, due to the potential for water contamination at the surface. Therefore, the systems may be susceptible to borated water leakage and subsequent boric acid corrosion.	Air with borated water leakage
Heat and air Moisture and air Radiation and air	Condition in a limited plant area that is significantly more severe than the plant design environment for the cable or connection insulation materials caused by heat, radiation, or moisture and air.	Adverse localized environment caused by heat, radiation or moisture
Significant moisture	Condition in a limited plant area that is significantly more severe than the plant design environment for the cable or connection insulation materials caused by significant moisture (moisture that lasts more than a few days—e.g., cable submerged in standing water).	Adverse localized environment caused by significant moisture

3.1. AGING MANAGEMENT OF REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

3.1.1. Introduction

This section provides the results of the AMR for those components identified in Section 2.3.1, Reactor Vessel, Internals, and Reactor Coolant system, as being subject to AMR. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Reactor Vessel (2.3.1.1)
- Reactor Vessel Internals (2.3.1.2)
- Pressurizers (2.3.1.3)
- Reactor Coolant and Connected Piping (2.3.1.4)
- Steam Generators (2.3.1.5)

3.1.2. Results

The following tables summarize the results of the AMR for the reactor coolant system.

Table 3.1.2-1, Reactor Vessel – Summary of Aging Management Evaluation

Table 3.1.2-2, Reactor Vessel Internals – Summary of Aging Management Evaluation

Table 3.1.2-3, Pressurizers – Summary of Aging Management Evaluation

Table 3.1.2-4, Reactor Coolant and Connected Piping – Summary of Aging Management Evaluation

Table 3.1.2-5, Steam Generators – Summary of Aging Management Evaluation

3.1.2.1. Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.1.2.1.1. Reactor Vessel

Materials

The materials of construction for the reactor vessel components are:

- Carbon steel
- Carbon steel with stainless steel clad
- High-strength steel
- Nickel alloy
- Stainless steel

Environments

The reactor vessel components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Neutron flux
- Reactor coolant

Aging Effects Requiring Management

The following aging effects associated with the reactor vessel require management:

- Cracking
- Cumulative fatigue damage
- Loss of fracture toughness
- Loss of material

Aging Management Programs

The following AMPs manage the aging effects for the reactor vessel components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)
- Boric Acid Corrosion (B.2.3.4)
- Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in RCPB Components (B.2.3.5)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Neutron Fluence Monitoring (B.2.2.2)
- Reactor Head Closure Stud Bolting (B.2.3.3)
- Reactor Vessel Material Surveillance (B.2.3.19)
- Water Chemistry (B.2.3.2)

3.1.2.1.2. Reactor Vessel Internals

The materials of construction for the reactor vessel internals components are:

- Cast austenitic stainless steel
- Nickel alloy
- Stainless steel
- Stellite

Environments

The reactor vessel internals components are exposed to the following environments:

- Neutron flux
- Reactor coolant

Aging Effects Requiring Management

The following aging effects associated with the reactor vessel internals require management:

- Changes in dimensions
- Cracking
- Cumulative fatigue damage
- Loss of fracture toughness
- Loss of material
- Loss of preload
- Wear

Aging Management Programs

The following AMPs manage the aging effects for the reactor vessel internals components:

- ASME Section XI Inservice Inspection (B.2.3.1)
- Flux Thimble Tube Inspection (B.2.3.24)
- Reactor Vessel Internals (B.2.3.7)
- Water Chemistry (B.2.3.2)

3.1.2.1.3. <u>Pressurizers</u>

Materials

The materials of construction for the pressurizer components are:

- Carbon steel
- Carbon steel with stainless steel clad
- Carbon steel with stainless steel insert
- Low-alloy steel
- Stainless steel
- Steel

Environments

The pressurizer components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Reactor coolant

Aging Effects Requiring Management

The following aging effects associated with the pressurizers require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the pressurizer components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD (B.2.3.1)
- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Water Chemistry (B.2.3.2)

3.1.2.1.4. Reactor Coolant and Connected Piping

Materials

The materials of construction for the reactor coolant and connected piping components are:

- Carbon steel
- CASS
- Stainless steel
- Steel

Environments

The Reactor Coolant and Connected Piping components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Condensation
- Reactor coolant
- Reactor coolant >482°F
- Treated borated water
- Treated borated water >140°F
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Reactor Coolant and Connected Piping require management:

- Cracking
- Cumulative fatigue damage
- Loss of fracture toughness
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Reactor Coolant and Connected Piping components:

- ASME Code Class 1 Small-Bore Piping (B.2.3.22)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD (B.2.3.1)
- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- One-Time Inspection (B.2.3.20)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B.2.3.6)
- Water Chemistry (B.2.3.2)

3.1.2.1.5. Steam Generators

Materials

The materials of construction for the steam generator components are:

- Carbon steel
- Carbon steel with nickel alloy clad
- Carbon steel with stainless steel clad
- Carbon steel with stainless steel insert
- Chrome-plated Alloy 600
- Low-alloy steel
- Nickel alloy
- Stainless steel

Environments

The steam generator components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Reactor coolant
- Steam
- Treated water
- Treated water >140°F

Aging Effects Requiring Management

The following aging effects associated with the steam generators require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning - FAC

Aging Management Programs

The following AMPs manage the aging effects for the steam generator components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD (B.2.3.1)
- Bolting Integrity (B.2.3.9)

- Boric Acid Corrosion (B.2.3.4)
- Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in RCPB Components (B.2.3.5)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.8)
- One-Time Inspection (B.2.3.20)
- Steam Generators (B.2.3.10)
- Water Chemistry (B.2.3.2)

3.1.2.2. AMR Results for Which Further Evaluation is Recommended by the GALL Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Reactor Coolant system, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

3.1.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). These types of TLAAs are addressed separately in Section 4.3, "Metal Fatigue," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Cumulative fatigue damage for applicable reactor coolant systems components is an aging effect assessed by a time-limited aging analysis (TLAA) in Section 4.3.1, Metal Fatigue of Class 1 Components.

3.1.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

1. *Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR SG upper and lower shell and transition cone exposed to secondary feedwater and steam. The existing program relies on control of water chemistry to mitigate corrosion and inservice inspection (ISI) to detect loss of material. The extent and schedule of the existing SG inspections are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the welds. However, according to NRC Information Notice (IN) 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," the program may not be sufficient to detect pitting and crevice corrosion if general and pitting corrosion of the shell is known to exist. Augmented inspection is recommended to manage this aging effect. Furthermore, this issue is limited to Westinghouse Model 44 and 51 Steam Generators, where a high-stress region exists at the shell to transition cone weld. Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP-SLR).*

The PBN Unit 1 steam generators are a Westinghouse Model 44F design per Section 2.3.1.5 and the design includes a high-stress region at the shell to transition cone welds. Loss of material due to general, pitting, and crevice corrosion in the Unit 1 lower shell to transition cone weld and transition cone to upper shell weld will be managed by the Water Chemistry and American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMPs. These two welds (lower shell to transition cone and transition cone to upper shell) are original welds. The enhanced examination techniques described in IN 90-04 are consistent with the techniques currently used in the PBN ASME Section XI Inservice Inspection, Subsections IWB, IWC, IWD AMP for the original transition cone welds, and no further augmented inspection is required.

The PBN Unit 2 steam generators are a Westinghouse Model Δ47 design per Section 2.3.1.5. The Model Δ47 design eliminates the weld at the high-stress region between the transition cone and shell. As such loss of material due to general, pitting, and crevice corrosion of the steam generator transition cone welds is not an applicable aging effect for PBN Unit 2.

2. *Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR steam generator shell assembly exposed to secondary feedwater and steam. The existing program relies on control of secondary water chemistry to mitigate corrosion. However, some applicants have replaced only the bottom part of their recirculating SGs, generating a cut in the middle of the transition cone, and, consequently, a new transition cone closure weld. It is recommended that volumetric examinations be performed in accordance with the requirements of ASME Code Section XI for upper shell and lower shell-to-transition cones with gross structural discontinuities for managing loss of material due to general, pitting, and crevice corrosion in the welds for Westinghouse Model 44 and 51 SGs, where a high-stress region exists at the shell-to-transition cone weld.*

   The new continuous circumferential weld, resulting from cutting the transition cone as discussed above, is a different situation from the SG transition cone welds containing geometric discontinuities. Control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations of stagnant flow conditions. The new transition area weld is a field weld as opposed to having been made in a controlled manufacturing facility, and the surface conditions of the transition weld may result in flow conditions more conducive to initiation of general, pitting, and crevice corrosion than those of the upper and lower transition cone welds. Crediting of the ISI program for the new SG transition cone weld may not be an effective basis for managing loss of material in this weld, as the ISI criteria would only perform a VT-2 visual leakage examination of the weld as part of the system leakage test performed pursuant to ASME Code Section XI requirements. In addition, ASME Code Section XI does not require licensees to remove insulation when performing visual examination on nonborated treated water systems. Therefore, the effectiveness of the chemistry control program should be verified to ensure that loss of material due to general, pitting and crevice corrosion is not occurring.

For the new continuous circumferential weld, further evaluation is recommended to verify the effectiveness of the chemistry control program. A one-time inspection at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly, such that the component's intended function will be maintained during the subsequent period of extended operation. Furthermore, this issue is limited to replacement of recirculating SGs with a new transition cone closure weld.

PBN Units 1 and 2 began commercial operation with Westinghouse Model 44 steam generators. In 1983, PBN replaced the lower assemblies of the Unit 1 Model 44 steam generators with Westinghouse Model 44F steam generator lower assemblies. This replacement was accomplished through a circumferential cut in the middle of the transition cone for each steam generator, followed by a closure weld performed in the field connecting the new lower assembly to the existing steam dome. In 1996, PBN installed the Westinghouse Model Δ47 steam generators in Unit 2. To allow passage of the steam generators through the containment hatch, the steam generators were cut in the middle of the transition cone and reassembled with a circumferential closure weld performed in the field connecting the upper and lower steam generator sections. The Unit 1 and 2 internal surface conditions of the new circumferential field welds may result in flow conditions more conducive to initiation of general, pitting, and crevice corrosion. The new circumferential closure welds will be managed by the Water Chemistry (B.2.3.2) AMP. In addition, a one-time Inspection, in accordance with the One- Time Inspection AMP, of the new circumferential closure welds will be conducted to verify the effectiveness of the Water Chemistry (B.2.3.2) AMP in managing general and pitting corrosion of the Unit 1 and Unit 2 steam generator shells. This inspection will be a volumetric inspection consistent with the techniques currently in place for the original transition cone welds for Unit 1 discussed in Section 3.1.2.2.2.1 and will be performed prior to entering the (SPEO).

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

1. *Neutron irradiation embrittlement is a TLAA to be evaluated for the subsequent period of extended operation for all ferritic materials that have a neutron fluence greater than 10^{17} n/cm2 (E >1 MeV) at the end of the subsequent period of extended operation. Certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.2, "Reactor Pressure Vessel Neutron Embrittlement Analysis," of this SRP-SLR.*

   Loss of fracture toughness due to neutron irradiation embrittlement is an aging effect and mechanism evaluated by a time limited aging analysis (TLAA). The TLAA evaluation of neutron irradiation embrittlement is discussed in Section 4.2, "Reactor Vessel Neutron Embrittlement.

2. *Loss of fracture toughness due to neutron irradiation embrittlement could occur in BWR and PWR reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. A reactor vessel material surveillance*

program monitors neutron irradiation embrittlement of the reactor vessel. The reactor vessel material surveillance program is either a plant-specific surveillance program or an integrated surveillance program, depending on matters such as the composition of limiting materials and the availability of surveillance capsules.

In accordance with 10 CFR Part 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Untested capsules placed in storage must be maintained for future insertion. Thus, further NRC staff evaluation is required for a subsequent license renewal (SLR). Specific recommendations for an acceptable AMP are provided in GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance."

A neutron fluence monitoring program may be used to monitor the neutron fluence levels that are used as the time-dependent inputs for the plant's reactor vessel neutron irradiation embrittlement TLAAs. These TLAAs are the subjects of the topics discussed in SRP-SLR Section 3.1.2.2.3.1 and "acceptance criteria" and "review procedure" guidance in SRP-SLR Section 4.2. For those applicants that determine it is appropriate to include a neutron fluence monitoring AMP in their SLRAs, the program is to be implemented in conjunction with the applicant's implementation of an AMP that corresponds to GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance." Specific recommendations for an acceptable neutron fluence monitoring AMP are provided in GALL-SLR Report AMP X.M2, "Neutron Fluence Monitoring."

Loss of fracture toughness due to neutron irradiation embrittlement could occur in the reactor vessel beltline, shells, nozzles, and welds. The neutron fluence TLAA is discussed in Section 4.2.1, Neutron Fluence Projections and is managed by the Neutron Fluence Monitoring (B.2.2.2) AMP, which is addressed in Section B.2.2.2. This AMP is consistent with 10 CFR Appendix H. The capsule withdrawal schedule has previously been approved by the NRC; however, an updated capsule withdrawal schedule is submitted for NRC approval in Appendix A to support the necessary lead time to represent 72 EFPY of exposure. The Neutron Fluence Monitoring (B.2.2.2) AMP monitors the plant conditions to ensure the assumptions of the Neutron Fluence Projections TLAA remain bounding and is implemented in conjunction with the Reactor Vessel Material Surveillance (B.2.3.19) AMP.

3. *Reduction in Fracture Toughness is a plant-specific TLAA for Babcock & Wilcox (B&W) reactor internals to be evaluated for the subsequent period of extended operation in accordance with the NRC staff's safety evaluation concerning "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals," B&W Owners Group report number BAW-2248, which is included in BAW-2248A, March 2000. Plant-specific TLAAs are addressed in Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR.*

   Not applicable. This further evaluation item is only applicable to Babcock & Wilcox reactor internals.

3.1.2.2.4 <u>Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking</u>

1. *Cracking due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC) could occur in stainless steel (SS) and nickel alloy reactor vessel (RV) flange leak detection lines of BWR light-water reactor facilities. The plant-specific operating experience (OE) and condition of the RV flange leak detection lines are evaluated to determine if SCC or IGSCC has occurred. The aging effect of cracking in SS and nickel alloy RV flange leak detection lines is not applicable and does not require management if (a) the plant-specific OE does not reveal a history of SCC or IGSCC and (b) a one-time inspection demonstrates that the aging effect is not occurring. The applicant documents the results of the plant-specific OE review in the SLRA. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that cracking is not occurring. If cracking has occurred, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking in RV flange leak detection lines.*

   Not applicable - BWR only.

2. *Cracking due to SCC and IGSCC could occur in SS BWR isolation condenser components exposed to reactor coolant. The existing program relies on control of reactor water chemistry to mitigate SCC and on ASME Code Section XI ISI to detect cracking. However, the existing program should be augmented to detect cracking due to SCC and IGSCC. An augmented program is recommended to include temperature and radioactivity monitoring of the shell-side water and eddy current testing of tubes to ensure that the component's intended function will be maintained during the subsequent period of extended operation. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

   Not applicable - BWR only.

3.1.2.2.5 <u>Crack Growth Due to Cyclic Loading</u>

Crack growth due to cyclic loading could occur in reactor pressure vessel (RPV) shell forgings clad with SS using a high-heat-input welding process. Therefore, the current licensing basis (CLB) may include flaw growth evaluations of intergranular separations (i.e., underclad cracks) that have been identified in the RPV-to-cladding welds for the vessel. The evaluations apply to SA-508 Class 2 RPV forging components where the cladding was deposited and welded to the vessel using a high-heat-input welding process. For CLBs that include these types of evaluations, the evaluations may need to be identified as TLAAs if they are determined to conform to the six criteria for defining TLAAs in 10 CFR 54.3(a). The methodology for evaluating the underclad flaw should be consistent with the flaw evaluation procedure and criterion in the ASME Code Section XI.2. See SRP-SLR, Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," for generic guidance for meeting the requirements of 10 CFR 54.21(c).

The PBN Units 1 and 2 RPV's and the replacement reactor vessel closure head (RVCH) forgings, are SA-508 Class 2 components which are potentially susceptible to crack growth due to cyclic loading if a high-heat-input welding process for the cladding is used. As discussed in Section 4.4.1.1 of NUREG-1839, the PBN Units 1 and 2 RPVs have neither underclad reheat cracking nor underclad cold cracking because the vessel manufacturers did not use the welding processes, post-weld heat treating practices, or materials that contributed to the cracking conditions. The PBN Units 1 and 2 vessels were fabricated using single layer cladding which was applied using one-wire cladding processes with low heat input that did not exhibit underclad reheat cracking in evaluations of either test samples or actual nozzle cutouts.

The Unit 1 and Unit 2 RVCHs were replaced in 2004 and 2005 respectively. During the manufacturing process of the new forgings, precautions were taken to preclude the potential for underclad cracking, including precautions to preclude the formation of segregated areas on the surface to be clad, the presence of stresses in the underclad heat affected zone (HAZ), and the presence of coarse grain areas in the cladding HAZ.

Thus, underclad cracking of the PBN RPVs and replacement heads does not meet the six criteria required for a TLAA.

3.1.2.2.6 Cracking Due to Stress Corrosion Cracking

1. *Cracking due to SCC could occur in PWR SS bottom-mounted instrument guide tubes exposed to reactor coolant. Further evaluation is recommended to ensure that these aging effects are adequately managed. A plant-specific AMP should be evaluated to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

   The effects of cracking due to SCC in the bottom-mounted instrumentation guide tubes are managed using the Water Chemistry (B.2.3.2) AMP and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP. The Water Chemistry (B.2.3.2) AMP will minimize the contaminants which promote SCC. VT-2 Inspections are performed as a part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP and will identify degradation of the stainless steel bottom-mounted instrumentation guide tubes.

2. *Cracking due to SCC could occur in Class 1 PWR cast austenitic stainless steel (CASS) reactor coolant system piping and piping components exposed to reactor coolant. The existing program relies on control of water chemistry to mitigate SCC; however, SCC could occur in CASS components that do not meet the NUREG–0313, "Technical Report on Material Selection and Process Guidelines for BWR Coolant Pressure Boundary Piping" guidelines with regard to ferrite and carbon content. Further evaluation is recommended of a plant-specific program for these components to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

Cracking due to SCC could occur in CASS components that do not meet the NUREG-0313 guidelines regarding ferrite and carbon content. However, review of NUREG-0313 describes industry experience where SCC of CASS components occurred in boiling water reactors (BWRs) primarily due to susceptible CASS components being exposed to BWR water chemistry with high levels of oxygen and other contaminants. NUREG-0313 does not identify SCC of CASS components as being problematic in pressurized water reactors (PWRs) like PBN. This can be attributed to the very tight controls of PWR water chemistry for dissolved oxygen and other aggressive contaminants. The lack of SCC in PBN Class 1 CASS piping and piping components is discussed in the Operating Experience discussion in Section B.2.3.6. Therefore, the Water Chemistry program is effective in managing the aging effects of cracking due to SCC in Class 1 RCS CASS piping and piping components and an additional plant specific program to manage aging is not required. The PBN disposition for 3.1.2.2.6, Item 2 is consistent with the disposition accepted for the Turkey Point Units 3 and 4 SLRA (Reference ML19191A057).

3. *Cracking due to SCC could occur in SS or nickel alloy RV flange leak detection lines of PWR light-water reactor facilities. The plant-specific OE and condition of the RV flange leak detection lines are evaluated to determine if SCC has occurred. The aging effect of cracking in SS and nickel alloy RV flange leak detection lines is not applicable and does not require management if (a) the plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring. The applicant documents the results of the plant-specific OE review in the SLRA. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that cracking is not occurring. If cracking has occurred, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking in RV flange leak detection lines.*

   Each of the PBN reactor vessel flange leak detection lines includes a 3/16-inch diameter orifice in the RPV flange which limits any potential RCS leakage to within the capacity of a charging pump in the unlikely event of leakage past the inner O-ring. Since the leak detection lines are nonsafety-related and their potential failure would not prevent satisfactory accomplishment of any safety-related functions, the leak detection lines do not perform or support any license renewal intended functions that meet the scoping criteria of 10 CFR 54.4(a) and an AMR is not required.

3.1.2.2.7 Cracking Due to Cyclic Loading

Cracking due to cyclic loading could occur in steel and SS BWR isolation condenser components exposed to reactor coolant. The existing program relies on ASME Code Section XI ISI. However, the existing program should be augmented to detect cracking due to cyclic loading. An augmented program is recommended to include temperature and radioactivity monitoring of the shell-side water and eddy current testing of tubes to ensure that the component's intended function will be maintained during the subsequent period of extended operation. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Not applicable - BWR only.

3.1.2.2.8 Loss of Material Due to Erosion

Loss of material due to erosion could occur in steel steam generator feedwater impingement plates and supports exposed to secondary feedwater. Further evaluation is recommended of a plant-specific AMP to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

This item is not applicable to PBN as a feedwater impingement plate is not a Westinghouse steam generator Model 44F (Unit 1) or Model Δ47 (Unit 2) component.

3.1.2.2.9 Aging Management of PWR Reactor Vessel Internals (Applicable to Subsequent License Renewal Periods Only)

Electric Power Research Institute (EPRI) Topical Report (TR)-1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)" (Agency wide Documents Access and Management System (ADAMS) Accession Nos. ML12017A191 through ML12017A197 and ML12017A199), provides the industry's current aging management recommendations for the reactor vessel internal (RVI) components that are included in the design of a PWR facility. In this report, the EPRI Materials Reliability Program (MRP) identified that the following aging mechanisms may be applicable to the design of the RVI components in these types of facilities: (a) SCC, (b) irradiation-assisted stress corrosion cracking (IASCC), (c) fatigue, (d) wear, (e) neutron irradiation embrittlement, (f) thermal aging embrittlement, (g) void swelling and irradiation growth, or (h) thermal or irradiation-enhanced stress relaxation or irradiation enhanced creep. The methodology in MRP-227-A was approved by the NRC in a safety evaluation dated December 16, 2011 (ADAMS Accession No. ML11308A770), which includes those plant-specific applicant/licensee action items that a licensee or applicant applying the MRP-227-A report would need to address and resolve and apply to its licensing basis.

The EPRI MRP's functionality analysis and failure modes, effects, and criticality analysis bases for grouping Westinghouse-designed, B&W-designed and Combustion Engineering (CE)-designed RVI components into these inspection categories was based on an assessment of aging effects and relevant time-dependent aging parameters through a cumulative 60-year licensing period (i.e., 40 years for the initial operating license period plus an additional 20 years during the initial period of extended operation). The EPRI MRP has not assessed whether operation of Westinghouse-designed, B&W-designed and CE-designed reactors during an SLR operating period would have any impact on the existing susceptibility rankings and inspection categorizations for the RVI components in these designs, as defined in MRP-227-A or its applicable MRP background documents (e.g., MRP-191 for Westinghouse-designed or CE-designed RVI components or MRP-189 for B&W-designed components).

As described in GALL-SLR Report AMP XI.M16A, the applicant may use the MRP-227-A based AMP as an initial reference basis for developing and defining the AMP that will be applied to the RVI components for the subsequent period of extended operation. However, to use this alternative basis, GALL-SLR Report AMP XI.M16A recommends that the MRP-227-A based AMP be enhanced to include a gap analysis of the components that are within the scope of the AMP. The gap analysis is a basis for identifying and justifying any potential changes to the MRP-227-A based program that may be necessary to provide reasonable assurance that the effects of age-related degradation will be managed during the subsequent period of extended operation. The criteria for the gap analysis are described in GALL-SLR Report AMP XI.M16A.

Alternatively, the PWR SLRA may define a plant-specific AMP for the RVI components to demonstrate that the RVI components will be managed in accordance with the requirements of 10 CFR 54.21(a)(3) during the proposed subsequent period of extended operation. Components to be inspected, parameters monitored, monitoring methods, inspection sample size, frequencies, expansion criteria, and acceptance criteria are justified in the SLRA. The NRC staff will assess the adequacy of the plant-specific AMP against the criteria for the 10 AMP program elements that are defined in Section A.1.2.3 of SRP-SLR Appendix A.1.

The PBN Reactor Vessel Internals AMP is based on the current MRP-227 Revision 1-A framework modified by an 80-year gap analysis. Appendix C of this application provides a detailed discussion of the RVI gap analysis. As enhanced, this program will continue to manage the effects of stress corrosion cracking, irradiation -assisted stress corrosion cracking, wear, fatigue, thermal aging embrittlement, irradiation embrittlement, void swelling, thermal and irradiation-induced stress relaxation, and irradiation creep, including any combined effects. As a condition monitoring program, the PBN Reactor Vessel Internals AMP specifies inspection methods that are sufficient to detect aging effects, such as cracking, whether from a single aging mechanism or combination of mechanisms, prior to a component approaching a condition in which it may not be able to fulfill its intended functions; and if such aging effects are detected, the evaluation and corrective action is required to consider the effects from any applicable mechanism in order to provide reasonable assurance that the component will continue to perform its intended function.

3.1.2.2.10 Loss of Material Due to Wear

1. *Industry OE indicates that loss of material due to wear can occur in PWR control rod drive (CRD) head penetration nozzles made of nickel alloy due to the interactions between the nozzle and the thermal sleeve centering pads of the nozzle (see Reference 29). The CRD head penetration nozzles are also called control rod drive mechanism (CRDM) nozzles or CRDM head adapter tubes. The applicant should perform a further evaluation to confirm the adequacy of a plant-specific AMP or analysis (with any necessary inspections) for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP. Alternatively, the applicant may perform an analysis with any necessary inspections to confirm*

that loss of material due to wear does not affect the intended function(s) of these CRD head penetration nozzles, consistent with the current licensing basis (CLB).

The most recent industry guidance in NSAL 18-1 (Reference ML18198A275) documents that this wear interaction will not affect the intended functions of the CRDM head adapters as PBN has a 14X14 guide tube configuration with gaps between the guide funnel and upper guide tube that limits flange wear and prevents flange separation. For a T-hot plant with a 14X14 guide tube configuration, the current recommendations are to continue to monitor the industry OE for this issue. PBN will perform 20 EFPY inspections of the reactor vessel heads in 2025 as a part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP and will include in these inspections any relevant industry OE that has developed. As such, the effects of loss of material due to wear in the CRDM head penetrations is managed using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP.

2. *Industry OE indicates that loss of material due to wear can occur in the SS thermal sleeves of PWR CRD head penetration nozzles due to the interactions between the nozzle and the thermal sleeve (e.g., where the thermal sleeve exits from the head penetration nozzle inside the reactor vessel as described in Reference 30). Therefore, the applicant should perform a further evaluation to confirm the adequacy of a plant-specific AMP for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP.*

   The recent industry operating experience regarding thermal sleeve flange wear is not applicable to PBN as the site specific design limits flange wear and prevents flange separation per NSAL-18-1 (Reference ML18198A275). PBN will continue to follow all applicable guidelines as discussed in the Appendix C RVI gap analysis.

3.1.2.2.11 Cracking Due to Primary Water Stress Corrosion Cracking

1. *Foreign OE in steam generators with a design similar to that of Westinghouse steam generators (particularly Model 51) has identified cracks due to primary water stress corrosion cracking (PWSCC) in steam generator (SG) divider plate assemblies fabricated of Alloy 600 and/or the associated Alloy 600 weld materials, even with proper primary water chemistry. Cracks have been detected in the stub runner with depths typically about 0.08 inches (EPRI 3002002850).*

   All but one of these instances of cracking has been detected in divider plate assemblies that are approximately 1.3 inches in thickness. For the cracks in the 1.3-inch thick divider plate assemblies, the cracks tend to be parallel to the divider-plate-to-stub-runner weld (i.e., run horizontally in parallel to the lower surface of the tubesheet). For the one instance of cracking in a divider plate assembly with a thickness greater than 1.3 inches, the cracking occurred in a divider plate assembly with a thickness of approximately 2.4 inches near *manufacturing marks on the upper end of the stub runner used for locating tubesheet holes. These flaws were estimated to be approximately 0.08-inch deep.*

Although these instances indicate that the water chemistry program may not be sufficient to manage cracking due to PWSCC in SG divider plate assemblies, analyses by the industry indicate that PWSCC in the divider plate assembly does not pose a structural integrity concern for other steam generator components (e.g., tubesheet and tube-to-tubesheet welds) and does not adversely affect other safety analyses (e.g., analyses supporting tube plugging and repairs, tube repair criteria, and design basis accidents). In addition, the industry analyses indicate that flaws in the divider plate assembly will not adversely affect the heat transfer function (as a result of bypass flow) during normal forced flow operation, during natural circulation conditions (assessed in the analyses of various design basis accidents), or in the event of a loss-of-coolant accident (LOCA).

Furthermore, additional industry analyses indicate that PWSCC in the divider plate assembly is unlikely to adversely impact adjacent items, such as the tubesheet cladding, tube-to-tubesheet welds, and channel head. Therefore,

- *For units with divider plate assemblies fabricated of Alloy 690 and Alloy 690 type weld materials, a plant-specific AMP is not necessary.*

- *For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the analyses performed by the industry (EPRI 3002002850) are applicable and bounding for the unit, a plant-specific AMP is not necessary.*

- *For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the industry analyses (EPRI 3002002850) are not bounding for the applicant's unit, a plant-specific AMP is necessary or a rationale is necessary for why such a program is not needed. A plant-specific AMP (one beyond the primary water chemistry and the steam generator programs) may include a one-time inspection that is capable of detecting cracking to verify the effectiveness of the water chemistry and steam generator programs and the absence of PWSCC in the divider plate assemblies.*

The existing programs rely on control of reactor water chemistry to mitigate cracking due to PWSCC and general visual inspections of the channel head interior surfaces (included as part of the steam generator program). The GALL-SLR Report recommends further evaluation for a plant-specific AMP to confirm the effectiveness of the primary water chemistry and steam generator programs as described in this section. Acceptance criteria for a plant-specific AMP are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR). In place of a plant-specific AMP, the applicant may provide a rationale to justify why a plant-specific AMP is not necessary.

PBN Unit 1 has an Alloy 600 divider plate assemblies and the EPRI analysis is applicable. The industry analysis (EPRI TR-3002002850) are currently being evaluated as part of the existing steam generators AMP for the current period of extended operation to determine whether it is bounding for PBN.

If the analysis is determined to be bounding, the Steam Generators AMP will be revised to address primary water stress corrosion cracking in the divider plate for the current period of extended operation and carried forward through the SPEO. A plant specific AMP is not necessary.

If the analyses are determined to not be bounding, a one-time inspection AMP will be implemented for SLR to verify the effectiveness of the Water Chemistry (B.2.3.2) and Steam Generators (B.2.3.10) AMP's. The examinations will be performed by qualified personnel and the techniques used will be capable of detection of primary water stress corrosion cracking in the divider plate assemblies and associated welds.

2. *Cracking due to PWSCC could occur in SG nickel alloy tube-to-tubesheet welds exposed to reactor coolant. The acceptance criteria for this review are:*

   For units with Alloy 600 SG tubes for which an alternate repair criterion such as C, F*, H*, or W* has been permanently approved for both the hot- and cold-leg side of the steam generator, the weld is no longer part of the reactor coolant pressure boundary and a plant-specific AMP is not necessary;*

   - *For units with Alloy 600 steam generator tubes, if there is no permanently approved alternate repair criteria such as C*, F*, H*, or W*, or permanent approval applies to only either the hot- or cold-leg side of the steam generator, a plant-specific AMP is necessary;*

   - *For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 690 type material, a plant-specific AMP is not necessary;*

   - *For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 600 type material, a plant-specific AMP is necessary unless the applicant confirms that the industry's analyses for tube-to-tubesheet weld cracking (e.g., chromium content for the tube-to-tubesheet welds is approximately 22 percent and the tubesheet primary face is in compression as discussed in EPRI 3002002850) are applicable and bounding for the unit, and the applicant will perform general visual inspections of the tubesheet region looking for evidence of cracking (e.g., rust stains on the tubesheet cladding) as part of the steam generator program. In lieu of a plant-specific AMP, the applicant may provide a rationale for why a plant-specific AMP is not necessary.*

   The existing programs rely on control of reactor water chemistry to mitigate cracking due to PWSCC and visual inspections of the steam generator head interior surfaces. Along with the primary water chemistry and steam generator programs, a plant-specific AMP should be evaluated to confirm the effectiveness of the primary water chemistry and steam generator programs in certain circumstances. A plant-specific AMP may include a one-time inspection that is capable of detecting cracking to confirm the absence of PWSCC in the *tube-to-tubesheet welds. Acceptance criteria for a plant-specific AMP are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR). In place of a plant-specific AMP, the applicant may provide a rationale to justify why a plant-specific AMP is not necessary.*

PBN Unit 1 has a permanently approved H* alternate repair criteria for both the hot- and cold-leg side of the steam generator (Reference ML17159A778). As such, the tube-to-tubesheet welds are no longer part of the reactor coolant pressure boundary, and a plant-specific AMP is not necessary.

PBN Unit 2 has thermally treated Alloy 690 SG tubes with tubesheet cladding using Alloy 690 type material. As such, a plant-specific AMP is not necessary.

3.1.2.2.12 Cracking Due to Irradiation-Assisted Stress Corrosion Cracking

GALL-SLR Report AMP XI.M9, "BWR Vessel Internals," manages aging degradation of nickel alloy and SS, including associated welds, which are used in BWR vessel internal components. When exposed to the BWR vessel environment, these materials can experience cracking due to IASCC. The existing Boiling Water Reactor Vessel and Internals Project (BWRVIP) examination guidelines are mainly based on aging evaluation of BWR vessel internals for operation up to 60 years. However, increases in neutron fluence during the SLR term may need to be assessed for supplemental inspections of BWR vessel internals to adequately manage cracking due to IASCC. Therefore, the applicant should perform an evaluation to determine whether supplemental inspections are necessary in addition to those recommended in the existing BWRVIP examination guidelines. If the applicant determines that supplemental inspections are not necessary, the applicant should provide adequate technical justification for the determination. If supplemental inspections are determined necessary for BWR vessel internals, the applicant identifies the components to be inspected and performs supplemental inspections to adequately manage IASCC. In addition, the applicant should confirm the adequacy of any necessary supplemental inspections and enhancements to the BWR Vessel Internals Program.

Not applicable - BWR only.

3.1.2.2.13 Loss of Fracture Toughness Due to Neutron Irradiation or Thermal Aging Embrittlement

GALL-SLR Report AMP XI.M9 manages aging degradation of nickel alloy and SS, including associated welds, which are used in BWR vessel internal components. When exposed to the BWR vessel environment, these materials can experience loss of fracture toughness due to neutron irradiation embrittlement. In addition, CASS, precipitation-hardened (PH) martensitic SS (e.g., 15-5 and 17-4 PH steel) and martensitic SS (e.g., 403, 410, 431 steel) can experience loss of fracture toughness due to neutron irradiation or thermal aging embrittlement.

The existing BWRVIP examination guidelines are mainly based on aging evaluation of BWR vessel internals for operation up to 60 years. Increases in *neutron fluence and thermal embrittlement during the SLR term may need to be assessed for supplemental inspections of BWR vessel internals to adequately manage loss of fracture toughness due to neutron irradiation or thermal aging embrittlement. Therefore, the applicant should perform an evaluation to determine whether supplemental inspections are necessary in addition to those recommended in the existing BWRVIP examination guidelines. If the applicant determines that supplemental inspections are not necessary, the applicant should provide adequate technical justification for the determination. If supplemental inspections are determined necessary for BWR vessel internals, the applicant should identify the components to be inspected and perform supplemental inspections to adequately manage loss of fracture toughness. In addition, the applicant should confirm the adequacy of any necessary supplemental inspections and enhancements to the BWR Vessel Internals Program.*

Not applicable - BWR only.

3.1.2.2.14 Loss of Preload Due to Thermal or Irradiation-Enhanced Stress Relaxation

GALL-SLR Report AMP XI.M9 manages loss of preload due to thermal or irradiation-enhanced stress relaxation in BWR core plate rim holddown bolts. The issue is applicable to BWR-designed light water reactors that employ rim holddown bolts as the means for protecting the reactor's core plate from the consequences of lateral movement. The potential for such movement, if left unmanaged, could impact the ability of the reactor to be brought to a safe shutdown condition during an anticipated transient occurrence or during a postulated design-basis accident or seismic event. This issue is not applicable to BWR reactor designs that use wedges as the means of precluding lateral movement of the core plate because the wedges are fixed in place and are not subject to this type of aging effect and mechanism combination.

GALL-SLR Report AMP XI.M9 indicates that the inspections in the BWRVIP topical report, "BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines (BWRVIP-25)," are used to manage loss of preload due to thermal or irradiation-enhanced stress relaxation in BWR designs with core plate rim holddown bolts. However, in previous license renewal applications (LRAs), some applicants have identified that the inspection bases for managing loss of preload in BWRVIP-25 may not be capable of gaining access to the rim holddown bolts or are not sufficient to detect loss of preload on the components. For applicants that have identified this issue in their past LRAs, the applicants either committed to modifying the plant design to install wedges in the core plate designs or to submit an inspection plan, with a supporting core plate rim holddown bolt preload analysis for NRC approval at least 2 years prior to entering into the initial period of extended operation for the facility.

If an existing NRC-approved analysis for the bolts exists in the CLB and conforms to the definition of a TLAA, the applicant should identify the analysis as a TLAA for the SLRA and demonstrate how the analysis is acceptable in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii). Otherwise, if a new analysis will be performed to support an updated augmented inspection basis for the bolts for the subsequent period of extended operation, the NRC staff *recommends that a license renewal commitment be placed in the FSAR Supplement for the applicant to submit both the inspection plan and the supporting loss of preload analysis to the NRC staff for approval at least 2 years prior to entering into the subsequent period of extended operation for the facility. If loss of preload in the bolts is managed with an AMP that correlates to GALL-SLR Report AMP XI.M9, the inspection basis in the applicable BWRVIP report is reviewed for continued validity, or else augmented as appropriate.*

Not applicable - BWR only.

3.1.2.2.15 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice or pitting corrosion and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

There are no reactor coolant system stainless steel or steel piping or piping components within the scope of subsequent license renewal that are exposed to concrete at PBN. Where reactor coolant system piping is required to penetrate concrete, penetration sleeves are used. This is addressed further in Section 3.5.

3.1.2.2.16 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping and piping components exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage loss of material due to pitting or crevice corrosion. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

A review of PBN operating experience confirms halides are potentially present in both the indoor and outdoor environments at PBN. As such, all stainless steel RCS components exposed to an air-indoor uncontrolled environment in the Reactor Coolant system are susceptible to loss of material due to pitting and crevice corrosion and require management via an appropriate program. Consistent with the recommendation of NUREG-2191, loss of material of these components will be managed via the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP. This AMP provides for the management of aging effects through periodic visual inspection. Any visual evidence of loss of material will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program.

3.1.2.2.17 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in BTP IQMB-1 (Appendix A.2 of the SRP-SLR)

Quality assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.1.2.2.18 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs" in the SRP-SLR.

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

3.1.2.3. Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Reactor Vessel, Internals, and Reactor Coolant system components:

- Section 4.2, Reactor Vessel Neutron Embrittlement Analysis
- Section 4.3, Metal Fatigue
- Section 4.7, Other Plant-Specific TLAAs

3.1.3. Conclusion

The Reactor Vessel, Internals, Reactor Coolant system piping, fittings, and components that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Reactor Vessel, Internals, and Reactor Coolant system components are identified in the summaries in Section 3.1.2 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Reactor Vessel, Internals, Reactor Coolant system components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the CLB during the SPEO.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 001	Steel reactor vessel closure flange assembly components exposed to air-indoor uncontrolled	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel reactor vessel closure flange assembly components exposed to air-indoor uncontrolled is addressed as a TLAA in Section 4.3.1. Further evaluation is documented in subsection 3.1.2.2.1.
3.1-1, 002	Nickel alloy tubes and sleeves exposed to reactor coolant, secondary feedwater/steam	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of nickel alloy tubes exposed to reactor coolant or secondary feedwater/steam is addressed as a TLAA in Section 4.3.1. Further evaluation is documented in subsection 3.1.2.2.1.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 003	Stainless steel, nickel alloy reactor vessel internal components exposed to reactor coolant, neutron flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux is addressed as a TLAA in Section 4.3.1. Further evaluation is documented in subsection 3.1.2.2.1.
3.1-1, 004	Steel pressure vessel support skirt and attachment welds	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Not applicable. The PBN reactor vessel is nozzle supported and there is no support skirt.
3.1-1, 005	Steel, stainless steel, steel (with stainless steel or nickel alloy cladding) steam generator components, pressurizer relief tank components, piping components, bolting	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel, stainless steel, steel (with stainless steel or nickel alloy cladding) in steam generator components, pressurizer relief tank components, piping components, and bolting is addressed as a TLAA in Section 4.3.1. Further evaluation is documented in subsection 3.1.2.2.1.
3.1-1, 006	Not applicable. This line item only applies to BWRs.				
3.1-1, 007	Not applicable. This line item only applies to BWRs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 008	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy steam generator components exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel (with or without stainless steel or nickel alloy cladding) or nickel alloy steam generator components exposed to reactor coolant is addressed as a TLAA in Section 4.3.1. Further evaluation is documented in subsection 3.1.2.2.1.
3.1-1, 009	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy reactor coolant pressure boundary piping, piping components; other pressure retaining components exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of stainless steel, steel (with or without nickel alloy or stainless steel cladding) in reactor coolant pressure boundary piping, piping components, and other pressure retaining components exposed to reactor coolant is addressed as a TLAA in Section 4.3.1. Further evaluation is documented in subsection 3.1.2.2.1.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 010	Steel (with or without nickel alloy or stainless steel cladding), stainless steel, or nickel alloy reactor vessel components: nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel (with or without nickel alloy or stainless steel cladding), stainless steel, or nickel alloy in reactor vessel components including nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads; and welds exposed to reactor coolant is addressed as a TLAA in Section 4.3.1. Further evaluation is documented in subsection 3.1.2.2.1.
3.1-1, 011	Steel or stainless steel pump and valve closure bolting exposed to high temperatures and thermal cycles	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel or stainless steel pump and valve closure bolting exposed to high temperatures and thermal cycles is addressed as a TLAA in Section 4.3.1. Further evaluation is documented in subsection 3.1.2.2.1.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 012	Steel steam generator components: upper and lower shells, transition cone; new transition cone closure weld exposed to secondary feedwater or steam	Loss of material due to general, pitting, crevice corrosion	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	Yes (SRP-SLR Sections 3.1.2.2.2.1 and 3.1.2.2.2.2)	Loss of material due to general, pitting, and crevice corrosion will be managed using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) and Water Chemistry (B.2.3.2) AMPs for the Unit 1 original transition cone welds. The new transition cone circumferential welds on Units 1 and 2 will be managed using the Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs. Further evaluation is documented in subsection 3.1.2.2.2.
3.1-1, 013	Steel (with or without stainless steel or nickel alloy cladding) reactor vessel beltline shell, nozzle, and weld components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, SRP-SLR Section 4.2 "Reactor Pressure Vessel Neutron Embrittlement"	Yes (SRP-SLR Section 3.1.2.2.3.1)	Consistent with NUREG-2191. Reactor vessel neutron embrittlement is addressed as a TLAA in Section 4.2 which is credited for managing loss of fracture toughness in steel reactor vessel components exposed to reactor coolant and neutron flux. Further evaluation is documented in subsection 3.1.2.2.3.1.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 014	Steel (with or without cladding) reactor vessel beltline shell, nozzle, and weld components; exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	AMP XI.M31, "Reactor Vessel Material Surveillance," and AMP X.M2, "Neutron Fluence Monitoring"	Yes (SRP-SLR Section 3.1.2.2.3.2)	Consistent with NUREG-2191. Loss of fracture toughness due to neutron irradiation embrittlement of the steel reactor vessel beltline shell, nozzle and welds in the beltline region will be managed with the Reactor Vessel Material Surveillance (B.2.3.19) and Neutron Fluence Monitoring (B.2.2.2) AMPs. Further evaluation is documented in subsection 3.1.2.2.3.2.
3.1-1, 015	This line item only applies to B&W designs. PBN utilizes Westinghouse designed reactor vessels.				
3.1-1, 016	Not applicable. This line item only applies to BWRs.				
3.1-1, 017	Not applicable. This line item only applies to BWRs.				
3.1-1, 018	Reactor vessel shell fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat- input welding process exposed to reactor coolant	Crack growth due to cyclic loading	TLAA, SRP-SLR Section 4.7 "Other Plant-Specific TLAAs"	Yes (SRP-SLR Section 3.1.2.2.5)	Not applicable. Crack growth due to cyclic loading will not occur in the PBN reactor vessel shells. Further evaluation is documented in subsection 3.1.2.2.5.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 019	Stainless steel reactor vessel bottom-mounted instrument guide tubes (external to reactor vessel) exposed to reactor coolant	Cracking due to SCC	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.6.1)	The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) and Water Chemistry (B.2.3.2) AMPs are used to manage SCC in the stainless steel reactor vessel bottom-mounted instrument guide tubes exposed to reactor coolant. Further evaluation is documented in subsection 3.1.2.2.6.
3.1-1, 020	Cast austenitic stainless steel Class 1 piping, piping components exposed to reactor coolant	Cracking due to SCC	AMP XI.M2, "Water Chemistry" and plant specific aging management program	Yes (SRP-SLR Section 3.1.2.2.6.2)	The Water Chemistry (B.2.3.2) AMP is used to manage SCC in Class 1 CASS piping. A plant-specific AMP is not necessary for further management. Further evaluation is documented in subsection 3.1.2.2.6.2.
3.1-1, 021	Not applicable. This line item only applies to BWRs.				
3.1-1, 022	Steel steam generator feedwater impingement plate and support exposed to secondary feedwater	Loss of material due to erosion	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.8)	Not applicable. This component does not exist at PBN. Further evaluation is documented in subsection 3.1.2.2.8.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 025	Steel (with nickel alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M19, "Steam Generators." In addition, a plant- specific program is to be evaluated.	Yes (SRP-SLR Sections 3.1.2.2.11.1 and 3.1.2.2.11.2)	Not applicable. Further evaluation is documented in subsection 3.1.2.2.11.
3.1-1, 028	"Existing Programs" components: Stainless steel, nickel alloy Westinghouse control rod guide tube support pins, and Combustion Engineering thermal shield positioning pins; Zircaloy-4 Combustion Engineering incore instrumentation thimble tubes exposed to reactor coolant and neutron flux	Loss of material due to wear; cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, "PWR Vessel Internals," and AMP XI.M2, "Water Chemistry" (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. The PBN control rod guide tube support pins are a No Additional Measures component.
3.1-1, 029	Not applicable. This line item only applies to BWRs.				
3.1-1, 030	Not applicable. This line item only applies to BWRs.				
3.1-1, 031	Not applicable. This line item only applies to BWRs.				
3.1-1, 032	Stainless steel, nickel alloy, or CASS reactor vessel internals, core support structure (not already referenced as ASME Section XI Examination Category B- N-3 core support structure components in MRP-227- A), exposed to reactor coolant and neutron flux	Cracking, loss of material due to wear	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The PBN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP is used to manage cracking and loss of material in reactor vessel internal core support structures exposed to reactor coolant and neutron flux.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 033	Stainless steel, steel with stainless steel cladding Class 1 reactor coolant pressure boundary components exposed to reactor coolant	Cracking due to SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The PBN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) and Water Chemistry (B.2.3.2) AMPs are used to manage SCC in Class 1 reactor coolant pressure boundary components exposed to reactor coolant.
3.1-1, 034	Stainless steel, steel with stainless steel cladding pressurizer relief tank (tank shell and heads, flanges, nozzles) exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	No	Not applicable. The PBN pressurizer relief tank is not an ASME Section XI component. Cracking due to SCC in the stainless steel pressurizer relief tank exposed to treated borated water >140°F is managed with item number 3.1-1, 080.
3.1-1, 035	Stainless steel, steel with stainless steel cladding reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP is used to manage cracking due to cyclic loading in stainless steel, steel with stainless steel cladding reactor coolant system piping and fittings exposed to reactor coolant.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 036	Steel, stainless steel pressurizer integral support exposed to any environment	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP is used to manage cracking due to cyclic loading in the pressurizer support skirt and flange.
3.1-1, 037	Steel reactor vessel flange	Loss of material due to wear	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP is used to manage loss of material due to wear of the reactor vessel flange.
3.1-1, 038	Cast austenitic stainless steel Class 1 valve bodies and bonnets exposed to reactor coolant >250 °C (>482 °F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP is used to manage loss of fracture toughness in cast austenitic stainless steel Class 1 valve bodies and bonnets exposed to reactor coolant >482 °F.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 039	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy Class 1 piping, fittings and branch connections < NPS 4 exposed to reactor coolant	Cracking due to SCC (for stainless steel or nickel alloy surfaces exposed to reactor coolant only), IGSCC (for stainless steel or nickel alloy surfaces exposed to reactor coolant only), or thermal, mechanical, or vibratory loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," AMP XI.M2, "Water Chemistry," and XI.M35, "ASME Code Class 1 Small-Bore Piping"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) and Water Chemistry (B.2.3.2) and ASME Code Class 1 Small-Bore Piping (B.2.3.22) AMPs are used to manage cracking due to SCC in stainless steel piping < 4" exposed to reactor coolant.
3.1-1, 040	Steel with stainless steel or nickel alloy cladding; or stainless steel pressurizer components exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP is used to manage cracking due to cyclic loading in stainless steel, or steel with stainless steel cladding pressurizer components exposed to reactor coolant.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 040a	Nickel alloy core support pads; core guide lugs exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking due to SCC in the nickel alloy core support pads exposed to reactor coolant.
3.1-1, 041	Not applicable. This line item only applies to BWRs.				
3.1-1, 042	Steel with stainless steel or nickel alloy cladding; stainless steel primary side components; steam generator upper and lower heads, and tube sheet welds; pressurizer components exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking due to SCC and PWSCC in stainless steel or steel with stainless steel cladding pressurizer components exposed to reactor coolant.
3.1-1, 043	Not applicable. This line item only applies to BWRs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 044	Steel steam generator secondary manway and handhole cover seating surfaces exposed to treated water, steam	Loss of material due to erosion	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP is used to manage loss of material due to erosion of the steel steam generator secondary manway and handhole cover seating surfaces exposed to treated water, steam.
3.1-1, 045	Nickel alloy, steel with nickel alloy cladding reactor coolant pressure boundary components exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD," and AMP XI.M2, "Water Chemistry," and, for nickel-alloy, AMP XI.M11B, "Cracking of Nickel- Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in RCPB Components (PWRs Only)"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1), Water Chemistry (B.2.3.2), and Cracking of Nickel- Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B.2.3.5) AMPs are used to manage cracking due to PWSCC in nickel alloy reactor coolant pressure boundary components exposed to reactor coolant.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 046	Stainless steel, nickel alloy control rod drive head penetration pressure housings, reactor vessel nozzles, nozzle safe ends and welds exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD," and AMP XI.M2, "Water Chemistry," and, for nickel-alloy, AMP XI.M11B, "Cracking of Nickel- Alloy Components and Loss of Material Due to Boric Acid-induced corrosion in RCPB Components (PWRs Only)"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking due to SCC and PWSCC in stainless steel and steel with stainless steel cladding reactor coolant pressure boundary components exposed to reactor coolant.
3.1-1, 047	Stainless steel, nickel alloy control rod drive head penetration pressure housing exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking due to SCC and PWSCC in stainless steel CRDM head penetration pressure housings and penetrations nozzles exposed to reactor coolant.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 048	Steel external surfaces: reactor vessel top head, reactor vessel bottom head, reactor coolant pressure boundary piping or components adjacent to dissimilar metal (Alloy 82/182) welds exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion," and AMP XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid- Induced Corrosion in RCPB Components (PWRs Only)"	No	Consistent with NUREG-2191. The Boric Acid Corrosion (B.2.3.4) and Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B.2.3.5) AMPs are used to manage loss of material due to boric acid corrosion in reactor vessel steel external surfaces adjacent to dissimilar metal (Alloy 82/182) welds exposed to air with borated water leakage.
3.1-1, 049	Steel reactor vessel, piping, piping components in the reactor coolant pressure boundary of PWRs, and applicable exterior attachments, or steel steam generators in PWRs: external surfaces or closure bolting exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Consistent with NUREG-2191. The Boric Acid Corrosion (B.2.3.4) AMP is used to manage loss of material due to boric acid corrosion in reactor coolant system steel external surfaces or closure bolting exposed to air with borated water leakage.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 050	Cast austenitic stainless steel Class 1 piping, piping components (including pump casings and control rod drive pressure housings) exposed to reactor coolant >250 °C (>482 °F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless steel (CASS)"	No	Consistent with NUREG-2191. The Thermal Aging Embrittlement of CASS (B.2.3.6) AMP is used to manage loss of fracture toughness due to thermal aging embrittlement in Class 1 CASS piping and pump casings and main flanges exposed to reactor coolant >482 °F.
3.1-1, 051a	Not applicable. This line item only applies to Babcock & Wilcox designs.				
3.1-1, 051b	Not applicable. This line item only applies to Babcock & Wilcox designs.				
3.1-1, 052a	Not applicable. This line item only applies to Combustion Engineering designs.				
3.1-1, 052b	Not applicable. This line item only applies to Combustion Engineering designs.				
3.1-1, 052c	Not applicable. This line item only applies to Combustion Engineering designs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 053a	Stainless steel, nickel alloy Westinghouse reactor internal "Primary" components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, "PWR Vessel Internals," and AMP XI.M2, "Water Chemistry" (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. The Reactor Vessel Internals (B.2.3.7) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking due to SCC, irradiation assisted SCC and fatigue in reactor vessel internals “Primary” components exposed to reactor coolant and neutron flux. Note that many aging effects managed by the Reactor Vessel Internals (B.2.3.7) AMP are dispositioned through FMECA analysis and not inspected. Further evaluation is documented in subsection 3.1.2.2.9.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 053b	Stainless steel Westinghouse reactor internal "Expansion" components exposed to reactor coolant and neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, "PWR Vessel Internals," and AMP XI.M2, "Water Chemistry" (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. The Reactor Vessel Internals (B.2.3.7) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking due to SCC, irradiation assisted SCC and fatigue in reactor vessel internals “Expansion” components exposed to reactor coolant and neutron flux. Note that many aging effects managed by the Reactor Vessel Internals (B.2.3.7) AMP are dispositioned through FMECA analysis and not inspected. Further evaluation is documented in subsection 3.1.2.2.9.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 053c	Stainless steel, nickel alloy Westinghouse reactor internal "Existing Programs" components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, "PWR Vessel Internals," and AMP XI.M2, "Water Chemistry" (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. The Reactor Vessel Internals (B.2.3.7) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking due to SCC, irradiation assisted SCC and fatigue in reactor vessel internals "Existing Programs" components exposed to reactor coolant and neutron flux. Note that many aging effects managed by the Reactor Vessel Internals (B.2.3.7) AMP are dispositioned through FMECA analysis and not inspected. Further evaluation is documented in subsection 3.1.2.2.9.
3.1-1, 054	Stainless steel bottom mounted instrument system flux thimble tubes (with or without chrome plating) exposed to reactor coolant and neutron flux	Loss of material due to wear	AMP XI.M37, "Flux Thimble Tube Inspection"	No	Consistent with NUREG-2191. The Flux Thimble Tube Inspection (B.2.3.24) AMP is used to manage loss of material due to wear in stainless steel bottom mounted instrument system flux thimble tubes exposed to reactor coolant and neutron flux.
3.1-1, 055a	Not applicable. This line item only applies to Babcock and Wilcox designs.				
3.1-1, 055b	Not applicable. This line item only applies to Combustion Engineering designs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 055c	Stainless steel, nickel alloy Westinghouse reactor internal "No Additional Measures" components exposed to reactor coolant, neutron flux	No additional aging management for reactor internal "No Additional Measures" components unless required by ASME Section XI, Examination Category B-N-3 or relevant operating experience exists	AMP XI.M16A, "PWR Vessel Internals"	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. The Reactor Vessel Internals (B.2.3.7) AMP is used to manage reactor vessel internals “No Additional Measures” components exposed to reactor coolant and neutron flux. Note that aging effects managed by the Reactor Vessel Internals (B.2.3.7) AMP for “No Additional Measures” components are dispositioned through FMECA analysis and not inspected. Further evaluation is documented in subsection 3.1.2.2.9.
3.1-1, 056a	Not applicable. This line item only applies to Combustion Engineering designs.				
3.1-1, 056b	Not applicable. This line item only applies to Combustion Engineering designs.				
3.1-1, 056c	Not applicable. This line item only applies to Combustion Engineering designs.				
3.1-1, 058a	Not applicable. This line item only applies to Babcock and Wilcox designs.				
3.1-1, 058b	Not applicable. This line item only applies to Babcock and Wilcox designs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 059a	Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Westinghouse reactor internal "Primary" components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, "PWR Vessel Internals"	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. The Reactor Vessel Internals (B.2.3.7) AMP is used to manage reactor vessel internals “Primary” components exposed to reactor coolant and neutron flux. Note that many aging effects managed by the Reactor Vessel Internals (B.2.3.7) AMP are dispositioned through FMECA analysis and not inspected. Further evaluation is documented in subsection 3.1.2.2.9.
3.1-1, 059b	Stainless steel (SS, including CASS, PH SS or martensitic SS) Westinghouse reactor internal "Expansion" components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, "PWR Vessel Internals"	Yes (SRP-SLR Section 3.1.2.2.9)	The Reactor Vessel Internals (B.2.3.7) AMP is used to manage reactor vessel internals “Expansion” components exposed to reactor coolant and neutron flux. Note that many aging effects managed by the Reactor Vessel Internals (B.2.3.7) AMP are dispositioned through FMECA analysis and not inspected. Further evaluation is documented in subsection 3.1.2.2.9.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 059c	Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Westinghouse reactor internal "Existing Programs" components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, "PWR Vessel Internals"	Yes (SRP-SLR Section 3.1.2.2.9)	The Reactor Vessel Internals (B.2.3.7) AMP is used to manage reactor vessel internals “Expansion” components exposed to reactor coolant and neutron flux. Note that many aging effects managed by the Reactor Vessel Internals (B.2.3.7) AMP are dispositioned through FMECA analysis and not inspected. Further evaluation is documented in subsection 3.1.2.2.9.
3.1-1, 060	Not applicable. This line item only applies to BWRs.				
3.1-1, 061	Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam	Wall thinning due to flow- accelerated corrosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion (B.2.3.8) AMP is used to manage wall thinning due to flow accelerated corrosion in the steam generator feedwater nozzle and steam outlet nozzle exposed to secondary feedwater/steam.
3.1-1, 062	High-strength steel, stainless steel closure bolting; stainless steel control rod drive head penetration flange bolting exposed to air-indoor uncontrolled	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage cracking due to SCC in RCPB stainless steel bolting exposed to air-indoor uncontrolled.
3.1-1, 063	Not applicable. This line item only applies to BWRs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 064	Steel or stainless steel closure bolting exposed to air – indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion, wear	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage loss of material due to general (steel only) pitting, crevice corrosion, and wear in steel and stainless steel closure bolting exposed to air-indoor uncontrolled.
3.1-1, 065	Stainless steel control rod drive head penetration flange bolting exposed to air-indoor uncontrolled	Loss of material due to wear	AMP XI.M18, "Bolting Integrity"	No	Not applicable. The control rod drive head penetration flange is not attached using bolting exposed to air-indoor uncontrolled.
3.1-1, 066	Steel, stainless steel closure bolting; stainless steel control rod drive head penetration flange bolting exposed to air-indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage loss of preload due to thermal effects, gasket creep, and self-loosening in the pressurizer manway cover bolts and RCS piping and piping components bolting exposed to air-indoor uncontrolled.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 067	Steel or stainless steel closure bolting exposed to air – indoor uncontrolled (external)	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage loss of preload due to thermal effects, gasket creep, and self-loosening in the steam generator primary manway and secondary closure bolting exposed to air-indoor uncontrolled (external).
3.1-1, 068	Nickel alloy steam generator tubes exposed to secondary feedwater or steam	Changes in dimension ("denting") due to corrosion of carbon steel tube support plate	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Not applicable. The PBN steam generator tube support plates are not carbon steel.
3.1-1, 069	Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam	Cracking due to outer diameter SCC, intergranular attack	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The Steam Generators (B.2.3.10) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking in nickel alloy U-tubes.
3.1-1, 070	Nickel alloy steam generator tubes, repair sleeves, and tube plugs exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The Steam Generators (B.2.3.10) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking due to primary water SCC in nickel alloy U-tubes and tube plugs exposed to reactor coolant.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 071	Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti-vibration bars exposed to secondary feedwater or steam	Cracking due to SCC or other mechanism(s); loss of material due general (steel only), pitting, crevice corrosion	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 The Steam Generators (B.2.3.10) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking, loss of material due to general (steel only), pitting, and crevice corrosion in steel, chrome plated-steel, stainless steel, and nickel alloy steam generator components exposed to treated feedwater and steam.
3.1-1, 072	Steel steam generator tube support plate, tube bundle wrapper, supports and mounting hardware exposed to secondary feedwater or steam	Loss of material due to general, pitting, crevice corrosion, erosion, ligament cracking due to corrosion	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry" (corrosion based aging effects and mechanisms only)	No	Consistent with NUREG-2191 The Steam Generators (B.2.3.10) and Water Chemistry (B.2.3.2) AMPs are used to manage loss of material due to general, pitting, and crevice corrosion, erosion, and ligament cracking due to corrosion in the steam generator tube bundle wrapper, moisture separators, and tubesheet exposed to secondary feedwater or steam.
3.1-1, 073	Nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater or steam	Loss of material due to wastage, pitting corrosion	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Not applicable. Phosphate chemistry is not used in the PBN Steam Generators (B.2.3.10).

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 074	Steel steam generator upper assembly and separators including feedwater inlet ring and support exposed to secondary feedwater or steam	Wall thinning due to flow- accelerated corrosion	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The Steam Generators (B.2.3.10) and Water Chemistry (B.2.3.2) AMPs are used to manage wall thinning due to flow-accelerated corrosion in the feedwater ring and moisture separators exposed to secondary feedwater or steam.
3.1-1, 075	Steel steam generator tube support lattice bars exposed to secondary feedwater or steam	Wall thinning due to flow- accelerated corrosion, general corrosion	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	Not applicable. Tube support lattice bars are not a PBN steam generator component.
3.1-1, 076	Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti-vibration bars exposed to secondary feedwater or steam	Loss of material due to wear, fretting	AMP XI.M19, "Steam Generators"	No	Consistent with NUREG-2191. The Steam Generators (B.2.3.10) AMP is used to manage loss of material due to wear, fretting of the steam generator anti-vibration bars and tube support plates exposed to secondary feedwater or steam.
3.1-1, 077	Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam	Loss of material due to wear, fretting	AMP XI.M19, "Steam Generators"	No	Consistent with NUREG-2191. The Steam Generators (B.2.3.10) AMP is used to manage loss of material due to wear, fretting of the U-tubes exposed to secondary feedwater or steam.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 078	Nickel alloy steam generator components such as, secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater or steam	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection," or AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."	No	Not used. All nickel alloy components on the secondary side of the steam generator address management of cracking due to SCC using more specific line items.
3.1-1, 079	Not applicable. This line item only applies to BWRs.				
3.1-1, 080	Stainless steel or steel with stainless steel cladding pressurizer relief tank: tank shell and heads, flanges, nozzles (none-ASME Section XI components) exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage cracking due to SCC of the pressurizer relief tank shell, heads, flanges, and nozzles.
3.1-1, 081	Stainless steel pressurizer spray head exposed to reactor coolant	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. Consistent with 2.3.1.4 of NUREG-1839, the pressurizer spray head is not within the scope of subsequent license renewal at PBN.
3.1-1, 082	Nickel alloy pressurizer spray head exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. Consistent with 2.3.1.4 of NUREG-1839, the pressurizer spray head is not within the scope of subsequent license renewal at PBN.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 083	Steel steam generator shell assembly exposed to secondary feedwater or steam	Loss of material due to general, pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. Loss of material of steam generator shell assembly exposed to secondary feedwater or steam is addressed in row 3.1-1, 012. The associated NUREG-2191 aging items are not used.
3.1-1, 084	Not applicable. This line item only applies to BWRs.				
3.1-1, 085	Not applicable. This line item only applies to BWRs.				
3.1-1, 086	Stainless steel steam generator primary side divider plate exposed to reactor coolant	Cracking due to SCC	AMP XI.M2, "Water Chemistry"	No	Not applicable. The steam generator primary side divider plates at PBN are nickel alloy.
3.1-1, 087	Stainless steel, nickel alloy PWR reactor internal components exposed to reactor coolant, neutron flux	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry"	No	Not applicable. Loss of material for reactor vessel internal components exposed to reactor coolant and neutron flux is addressed in rows 3.1-1, 059a, 3.1-1, 059b, 3.1-1, 059c, and 3.1-1, 119. While these items address loss of material due to wear, the reactor vessel internals AMR depends on the screening performed in MRP-191 which does not distinguish loss of material mechanisms.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 088	Stainless steel; steel with nickel alloy or stainless steel cladding; and nickel alloy reactor coolant pressure boundary components exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191. The Water Chemistry (B.2.3.2) AMP is used to manage loss of material due to pitting and crevice corrosion in stainless steel, nickel alloy, and steel with stainless steel cladding reactor coolant pressure boundary components exposed to reactor coolant.
3.1-1, 089	Steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There is no steel piping or piping components exposed to closed-cycle cooling water in the PBN reactor coolant system.
3.1-1, 090	Copper alloy piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no copper Class 1 piping or piping components at PBN.
3.1-1, 091	Not applicable. This line item only applies to BWRs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 092	Steel (including high- strength steel) reactor vessel closure flange assembly components (including flanges, nut, studs, and washers) exposed to air-indoor uncontrolled	Cracking due to SCC, IGSCC; loss of material due to general, pitting, crevice corrosion, wear	AMP XI.M3, "Reactor Head Closure Stud Bolting"	No	Consistent with NUREG-2191. The Reactor Head Closure Stud Bolting (B.2.3.3) AMP is used to manage cracking due to stress corrosion cracking, intergranular stress corrosion cracking, loss of material due to general, pitting, crevice corrosion, and wear of the reactor head closure studs exposed to air-indoor uncontrolled.
3.1-1, 093	Copper alloy >15% Zn or >8% Al piping, piping components exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no copper or aluminum piping or piping components in the PBN reactor coolant system.
3.1-1, 094	Not applicable. This line item only applies to BWRs.				
3.1-1, 095	Not applicable. This line item only applies to BWRs.				
3.1-1, 096	Not applicable. This line item only applies to BWRs.				
3.1-1, 097	Not applicable. This line item only applies to BWRs.				
3.1-1, 098	Not applicable. This line item only applies to BWRs.				
3.1-1, 099	Not applicable. This line item only applies to BWRs.				
3.1-1, 100	Not applicable. This line item only applies to BWRs.				
3.1-1, 101	Not applicable. This line item only applies to BWRs.				
3.1-1, 102	Not applicable. This line item only applies to BWRs.				
3.1-1, 103	Not applicable. This line item only applies to BWRs.				
3.1-1, 104	Not applicable. This line item only applies to BWRs.				

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 105	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.1.2.2.15)	Not applicable. There are no PBN reactor coolant system piping or piping components exposed to concrete. Further evaluation is documented in subsection 3.1.2.2.15.
3.1-1, 106	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not used. Boric acid corrosion is not an applicable aging effect for nickel alloy; the associated NUREG-2191 aging items are not used.
3.1-1, 107	Stainless steel piping, piping components exposed to gas, air with borated water leakage	None	None	No	Consistent with item number 3.1-1, 106, this line item is not used to recognize the lack of aging effects in stainless steel piping and piping components exposed to gas or air with borated water leakage.
3.1-1, 110	Not applicable. This line item only applies to BWRs.				
3.1-1, 111	Nickel alloy steam generator tubes exposed to secondary feedwater or steam	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M19, "Steam Generators"	No	Consistent with NUREG-2191. The Water Chemistry (B.2.3.2) and Steam Generators (B.2.3.10) AMPs are used to manage reduction of heat transfer due to fouling in the steam generator U-tubes exposed to secondary feedwater or steam.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 113	Not applicable. This line item only applies to BWRs.				
3.1-1, 114	Reactor coolant system components defined as ASME Section XI Code Class components (ASME Code Class 1 reactor coolant pressure boundary components or core support structure components, or ASME Class 2 or 3 components - including ASME defined appurtenances, component supports, and associated pressure boundary welds, or components subject to plant-specific equivalent classifications for these ASME code classes)	Cracking due to SCC, IGSCC (stainless steel, nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry" (water chemistry- related or corrosion- related aging effect mechanisms only)	No	Not used. All relevant aging mechanisms requiring management by ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) or Water Chemistry (B.2.3.2) are recognized using line items more specific to the individual component type.
3.1-1, 115	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.1.2.2.15)	Not applicable. There are no PBN stainless steel reactor coolant system piping or piping components exposed to concrete. Further evaluation is documented in subsection 3.1.2.2.15.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 116	Nickel alloy control rod drive penetration nozzles exposed to reactor coolant	Loss of material due to wear	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.10.1)	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.2) AMP is used to manage loss of material due to wear in the control rod drive mechanism head penetration housings exposed to reactor coolant. Further evaluation is documented in subsection 3.1.2.2.10.
3.1-1, 117	Stainless steel, nickel alloy control rod drive penetration nozzle thermal sleeves exposed to reactor coolant	Loss of material due to wear	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.10.2)	Not applicable. Further evaluation is documented in subsection 3.1.2.2.10.2.
3.1-1, 118	Stainless steel, nickel alloy PWR reactor vessel internal components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, cyclic loading, fatigue	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. Cracking due to SCC, irradiation-assisted SCC, cyclic loading, and fatigue of stainless steel, nickel alloy PWR reactor vessel internal components exposed to reactor coolant, neutron flux is addressed in rows 3.1-1, 053a, 3.1-1, 053b, and 3.1-1, 053c. The associated NUREG-2191 aging items are not used.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 119	Stainless steel, nickel alloy PWR reactor vessel internal components exposed to reactor coolant, neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement or thermal aging embrittlement; changes in dimensions due to void swelling or distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation or creep; loss of material due to wear	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191 for loss of fracture toughness and changes in dimensions. Loss of fracture toughness and changes in dimension for stainless steel reactor vessel internals components is managed by the Reactor Vessel Internals (B.2.3.7) AMP. Loss of preload is not applicable. Loss of material is addressed with item number 3.1-1, 054. Note that many aging effects managed by the Reactor Vessel Internals (B.2.3.7) AMP are dispositioned through FMECA analysis and not inspected. Further evaluation is documented in subsection 3.1.2.2.9.
3.1-1, 120	Not applicable. This line item only applies to BWRs.				
3.1-1, 121	Not applicable. This line item only applies to BWRs.				
3.1-1, 124	Steel piping, piping components exposed to air-indoor uncontrolled, air- outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material due to general, pitting, and crevice corrosion in steel piping and piping components exposed to air.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 125	Nickel alloy steam generator tubes at support plate locations exposed to secondary feedwater or steam	Cracking due to flow- induced vibration, high- cycle fatigue	AMP XI.M19, "Steam Generators"	No	Consistent with NUREG-2191. The Steam Generators (B.2.3.10) AMP is used to manage cracking due to flow-induced vibration and high-cycle fatigue in U-tubes exposed to secondary feedwater or steam.
3.1-1, 127	Steel (with stainless steel or nickel alloy cladding) steam generator heads and tubesheets exposed to reactor coolant	Loss of material due to boric acid corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M19, "Steam Generators"	No	Consistent with NUREG-2191. The Water Chemistry (B.2.3.2) and Steam Generator (B.2.3.10) AMPs are used to manage loss of material due to boric acid corrosion in the steam generator channel head nozzles and tubesheet exposed to reactor coolant.
3.1-1, 128	Not applicable. This line item only applies to BWRs.				
3.1-1, 129	Not applicable. This line item only applies to BWRs.				
3.1-1, 133	Not applicable. This line item only applies to BWRs.				
3.1-1, 134	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. No non-metallic thermal insulation associated with reactor coolant piping and piping components does not perform a SLR intended function and is therefore not in scope.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 136	Stainless steel, nickel alloy piping, piping components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.1.2.2.16)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy piping and piping components exposed to air. Further evaluation is documented in subsection 3.1.2.2.16. This item is also used to manage the internal surface of the pressurizer relief tank. The One-Time Inspection AMP is used to manage loss of material due to pitting and crevice corrosion in the stainless steel exposed to condensation in the nitrogen filled section of the tank.
3.1-1, 137	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Not applicable. There are no copper alloy piping or piping components in the PBN reactor coolant system.

Table 3.1-1: Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.1-1, 139	Stainless steel, nickel alloy reactor vessel top head enclosure flange leakage detection line exposed to air-indoor uncontrolled, reactor coolant leakage	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," or AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes (SRP-SLR Section 3.1.2.2.6.3)	The PBN reactor vessel top head leak detection line is outside of the reactor coolant system pressure boundary and does not perform a SLR intended function. Further evaluation is documented in subsection 3.1.2.2.6.3. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage cracking due to SCC in the PBN reactor vessel seal table fittings.

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bottom head	Pressure boundary Structural support	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Bottom head	Pressure boundary Structural support	Carbon steel with stainless steel clad	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4) Cracking of Nickel Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components (B.2.3.5)	IV.A2.RP-379	3.1-1, 048	A
Bottom head	Pressure boundary Structural support	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-234	3.1-1, 046	C D
Bottom head	Pressure boundary Structural support	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Bottom mounted instrumentation guide tubes	Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Bottom mounted instrumentation guide tubes	Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bottom mounted instrumentation guide tubes	Pressure boundary Structural support	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-154	3.1-1, 019	E, 1
Bottom mounted instrumentation guide tubes	Pressure boundary Structural support	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Closure flange and studs	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.A2.RP-54	3.1-1, 001	A
Closure head dome and flange	Pressure boundary	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Closure head dome and flange	Pressure boundary	Carbon steel with stainless steel clad	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4) Cracking of Nickel Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components (B.2.3.5)	IV.A2.RP-379	3.1-1, 048	A
Closure head dome and flange	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-234	3.1-1, 046	C D
Closure head dome and flange	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Closure studs, nuts, washers	Mechanical closure	High-strength steel	Air – indoor uncontrolled (ext)	Cracking	Reactor Head Closure Stud Bolting (B.2.3.3)	IV.A2.RP-52	3.1-1, 092	B
Closure studs, nuts, washers	Mechanical closure	High-strength steel	Air – indoor uncontrolled (ext)	Loss of material	Reactor Head Closure Stud Bolting (B.2.3.3)	IV.A2.RP-53	3.1-1, 092	B
Closure studs, nuts, washers	Mechanical closure	High-strength steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.A2.R-17	3.1-1, 049	A
Core exit thermocouple nozzle assembly	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Core exit thermocouple nozzle assembly	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
Core exit thermocouple nozzle assembly	Pressure Boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-55	3.1-1, 047	A B
Core exit thermocouple nozzle assembly	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Core support pads	Structural Support	Nickel alloy	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-57	3.1-1, 040a	A B
Core support pads	Structural Support	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	D

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
CRDM head adapter	Pressure Boundary	Nickel alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
CRDM head adapter	Pressure Boundary	Nickel alloy	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2) Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in RCPB Components (B.2.3.5)	IV.A2.RP-186	3.1-1, 045	A B A
CRDM head adapter	Pressure Boundary	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
CRDM head adapter	Pressure Boundary	Nickel alloy	Reactor coolant	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.A2.R-413	3.1-1, 116	E, 2
CRDM latch housing	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
CRDM latch housing	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
CRDM latch housing	Pressure Boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-55	3.1-1, 047	A B

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
CRDM latch housing	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
CRDM rod travel housing	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
CRDM rod travel housing	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
CRDM rod travel housing	Pressure Boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-55	3.1-1, 047	A B
CRDM rod travel housing	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Instrumentation port head adapter flange	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Instrumentation port head adapter flange	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
Instrumentation port head adapter flange	Pressure Boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-55	3.1-1, 047	A B
Instrumentation port head adapter flange	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Instrumentation tube safe ends	Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Instrumentation tube safe ends	Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
Instrumentation tube safe ends	Pressure boundary Structural support	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-55	3.1-1, 047	C D
Instrumentation tube safe ends	Pressure boundary Structural support	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Instrumentation tubes	Pressure boundary Structural support	Nickel alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
Instrumentation tubes	Pressure boundary Structural support	Nickel alloy	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2) Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in RCPB Components (B.2.3.5)	IV.A2.RP-59	3.1-1, 045	A B A

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Instrumentation tubes	Pressure boundary Structural support	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Nozzle support pads and external support brackets	Structural Support	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Nozzle support pads and external support brackets	Structural Support	Carbon steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.A2.R-17	3.1-1, 049	A
Primary inlet and outlet nozzle safe ends	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Primary inlet and outlet nozzle safe ends	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
Primary inlet and outlet nozzle safe ends	Pressure Boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-234	3.1-1, 046	A B
Primary inlet and outlet nozzle safe ends	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Primary inlet and outlet nozzles	Pressure boundary Structural support	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Primary inlet and outlet nozzles	Pressure boundary Structural support	Carbon steel with stainless steel clad	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.A2.R-17	3.1-1, 049	A

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Primary inlet and outlet nozzles	Pressure boundary Structural support	Carbon steel with stainless steel clad	Neutron flux (int)	Loss of fracture toughness	Reactor Vessel Material Surveillance (B.2.3.19) Neutron Fluence Monitoring (B.2.2.2)	IV.A2.RP-229	3.1-1, 014	B A
Primary inlet and outlet nozzles	Pressure boundary Structural support	Carbon steel with stainless steel clad	Neutron flux (int)	Loss of fracture toughness	TLAA – Section 4.2, Reactor Vessel Neutron Embrittlement	IV.A2.R-84	3.1-1, 013	A
Primary inlet and outlet nozzles	Pressure boundary Structural support	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-234	3.1-1, 046	C D
Primary inlet and outlet nozzles	Pressure boundary Structural support	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Reactor vessel components subject to fatigue	Pressure boundary	Carbon steel (with stainless steel clad), stainless steel, nickel alloy	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.A2.R-219	3.1-1, 010	A
Refueling seal ledge	Structural Support	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Refueling seal ledge	Structural Support	Carbon steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.A2.R-17	3.1-1, 049	A
Safety injection nozzle safe ends	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Safety injection nozzle safe ends	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
Safety injection nozzle safe ends	Pressure Boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.A2.RP-234	3.1-1, 046	A
Safety injection nozzle safe ends	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Safety injection nozzles	Pressure Boundary	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Safety injection nozzles	Pressure Boundary	Carbon steel with stainless steel clad	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.A2.R-17	3.1-1, 049	A
Safety injection nozzles	Pressure Boundary	Carbon steel with stainless steel clad	Neutron flux (int)	Loss of fracture toughness	Reactor Vessel Material Surveillance (B.2.3.19) Neutron Fluence Monitoring (B.2.2.2)	IV.A2.RP-229	3.1-1, 014	B A
Safety injection nozzles	Pressure Boundary	Carbon steel with stainless steel clad	Neutron flux (int)	Loss of fracture toughness	TLAA – Section 4.2, Reactor Vessel Neutron Embrittlement	IV.A2.R-84	3.1-1, 013	A
Safety injection nozzles	Pressure Boundary	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-234	3.1-1, 046	C D
Safety injection nozzles	Pressure Boundary	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Seal table	Structural Support	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Seal table	Structural Support	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
Seal table fittings	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.A2.R-61b	3.1-1, 139	C
Seal table fittings	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
Seal table fittings	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-234	3.1-1, 046	C D
Seal table fittings	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	D
Shells (intermediate, lower, upper)	Pressure boundary	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Shells (intermediate, lower, upper)	Pressure boundary	Carbon steel with stainless steel clad	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.A2.R-17	3.1-1, 049	A
Shells (intermediate, lower, upper)	Pressure boundary	Carbon steel with stainless steel clad	Neutron flux (int)	Loss of fracture toughness	TLAA – Section 4.2, Reactor Vessel Neutron Embrittlement	IV.A2.R-84	3.1-1, 013	A

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Shells (intermediate, lower, upper)	Pressure boundary	Carbon steel with stainless steel clad	Neutron flux (int)	Loss of fracture toughness	Reactor Vessel Material Surveillance (B.2.3.19) Neutron Fluence Monitoring (B.2.2.2)	IV.A2.RP-229	3.1-1, 014	B A
Shells (intermediate, lower, upper)	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-234	3.1-1, 046	C D
Shells (intermediate, lower, upper)	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Vent pipe	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Vent pipe	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C
Vent pipe	Pressure Boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-234	3.1-1, 046	C D
Vent pipe	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	D
Vent pipe nozzle	Pressure Boundary	Nickel alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	C

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Vent pipe nozzle	Pressure Boundary	Nickel alloy	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2) Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in RCPB Components (B.2.3.5)	IV.A2.R-90	3.1-1, 045	A B A
Vent pipe nozzle	Pressure Boundary	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Ventilation shroud support structure	Structural Support	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Ventilation shroud support structure	Structural Support	Carbon steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.A2.R-17	3.1-1, 049	A
Vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.A2.R-17	3.1-1, 049	A
Vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.A2.RP-234	3.1-1, 046	C D

Table 3.1.2-1: Reactor Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	B
Vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.A2.R-87	3.1-1, 037	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

Plant Specific Notes

1. Per Section 3.1.2.2.6, cracking due to SCC in the bottom-mounted instrumentation guide tubes is managed using the Water Chemistry (B.2.3.2) and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMPs. Note that the Water Chemistry (B.2.3.2) AMP has an exception to the NUREG-2191 AMP description.
2. Per Section 3.1.2.2.10.1, loss of material due to wear in the CRDM head penetrations is managed using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP.

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Alignment and interfacing components (clevis bearing Stellite wear surfaces)	Structural support	Stellite	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7)	None	None	J, 3
Alignment and interfacing components (clevis bearing Stellite wear surfaces)	Structural support	Stellite	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	None	None	J, 3
Alignment and interfacing components (clevis insert bolts)	Structural support	Nickel alloy	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-399	3.1-1, 053c	B, 1
Alignment and interfacing components (clevis insert bolts)	Structural support	Nickel alloy	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Alignment and interfacing components (clevis insert bolts)	Structural support	Nickel alloy	Reactor coolant Neutron flux	Loss of material Loss of preload	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-285	3.1-1, 059c	B, 1
Alignment and interfacing components (clevis insert dowels)	Structural support	Nickel alloy	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Alignment and interfacing components (clevis insert dowels)	Structural support	Nickel alloy	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-399	3.1-1, 053c	B, 1

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Alignment and interfacing components (upper core plate alignment pins)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-355	3.1-1, 053c	D
Alignment and interfacing components (upper core plate alignment pins)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-299	3.1-1, 059c	B
Alignment and interfacing components (upper core plate alignment pins)	Structural support	Stellite	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	None	None	J, 3
Baffle-former assembly (baffle plates, baffle edge bolts, former plates)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-270a	3.1-1, 053a	B
Baffle-former assembly (baffle plates, baffle edge bolts, former plates)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-387	3.1-1, 053a	D
Baffle-former assembly (baffle plates, baffle edge bolts, former plates)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Baffle-former assembly (baffle plates, former plates)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-270	3.1-1, 059a	B

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Baffle-former assembly (baffle plates, former plates)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-388	3.1-1, 059a	D
Baffle-former assembly (baffle-edge bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Changes in dimensions Loss of preload	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-354	3.1-1, 059a	B
Baffle-former assembly (baffle-edge bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-296	3.1-1, 059a	D
Baffle-former assembly (baffle-former bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-271	3.1-1, 053a	B
Baffle-former assembly (baffle-former bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Baffle-former assembly (baffle-former bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Changes in dimensions Loss of preload	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-354	3.1-1, 059a	B
Baffle-former assembly (baffle-former bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-296	3.1-1, 059a	D
Bottom mounted instrumentation (column bodies)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-293	3.1-1, 053b	B
Bottom mounted instrumentation (column bodies)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-290b	3.1-1, 059b	D

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bottom mounted instrumentation (flux thimble tubes)	Structural support Pressure boundary	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-355	3.1-1, 053c	D
Bottom mounted instrumentation (flux thimble tubes)	Structural support Pressure boundary	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Changes in dimensions	Reactor Vessel Internals (B.2.3.7)	IV.B2.R-424	3.1-1, 119	E, 2
Bottom mounted instrumentation (flux thimble tubes)	Structural support Pressure boundary	Stainless steel	Reactor coolant Neutron flux	Loss of material	Flux Thimble Tube Inspection (B.2.3.24)	IV.B2.RP-284	3.1-1, 054	A
Control rod guide tube assembly (guide cards)	Structural support	Cast austenitic stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-298	3.1-1, 053a	D
Control rod guide tube assembly (guide cards)	Structural support	Cast austenitic stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-297	3.1-1, 059a	D
Control rod guide tube assembly (guide cards)	Structural support	Cast austenitic stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-296	3.1-1, 059a	B
Control rod guide tube assembly (guide cards)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-298	3.1-1, 053a	D
Control rod guide tube assembly (guide cards)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-296	3.1-1, 059a	B
Control rod guide tube assembly (lower flange weld)	Structural support	Cast austenitic stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-298	3.1-1, 053a	B

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Control rod guide tube assembly (lower flange weld)	Structural support	Cast austenitic stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-297	3.1-1, 059a	B
Control rod guide tube assembly (lower flange weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-298	3.1-1, 053a	B
Control rod guide tube assembly (lower flange weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-297	3.1-1, 059a	B
Core barrel assembly (barrel former bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-273	3.1-1, 053b	B
Core barrel assembly (barrel former bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Changes in dimensions Loss of preload	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-274	3.1-1, 059b	B
Core barrel assembly (barrel former bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-296	3.1-1, 059a	D, 1
Core barrel assembly (core barrel flange)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-289	3.1-1, 053c	D
Core barrel assembly (core barrel flange)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Core barrel assembly (core barrel flange)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-345	3.1-1, 059c	B

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Core barrel assembly (core barrel outlet nozzle weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-278	3.1-1, 053b	B
Core barrel assembly (core barrel outlet nozzle weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Core barrel assembly (core barrel outlet nozzle weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-290b	3.1-1, 059b	D
Core barrel assembly (lower axial welds)	Structural support	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-274	3.1-1, 059b	D
Core barrel assembly (lower axial welds)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-387a	3.1-1, 053b	B
Core barrel assembly (lower axial welds)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Core barrel assembly (lower axial welds)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-388a	3.1-1, 059b	B
Core barrel assembly (lower flange weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-274	3.1-1, 059b	D
Core barrel assembly (lower flange weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-280	3.1-1, 053a	B, 1

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Core barrel assembly (lower flange weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Core barrel assembly (lower flange weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-388a	3.1-1, 059b	D
Core barrel assembly (lower girth weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-270	3.1-1, 059a	D
Core barrel assembly (lower girth weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-387	3.1-1, 053a	B
Core barrel assembly (lower girth weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Core barrel assembly (lower girth weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-388	3.1-1, 059a	B
Core barrel assembly (middle axial welds)	Structural support	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-274	3.1-1, 059b	D
Core barrel assembly (middle axial welds)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-387a	3.1-1, 053b	B
Core barrel assembly (middle axial welds)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Core barrel assembly (middle axial welds)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-388a	3.1-1, 059b	B

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Core barrel assembly (upper axial weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-387a	3.1-1, 053b	B
Core barrel assembly (upper axial weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Core barrel assembly (upper flange weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-276	3.1-1, 053a	B
Core barrel assembly (upper flange weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Core barrel assembly (upper girth weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-387	3.1-1, 053a	B, 1
Core barrel assembly (upper girth weld)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Lower core plate (fuel alignment pins)	Structural support	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-270	3.1-1, 059a	D, 1
Lower core plate (fuel alignment pins)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-289	3.1-1, 053c	D
Lower core plate (fuel alignment pins)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-288	3.1-1, 059c	D

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Lower internals assembly (lower core plate)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-270	3.1-1, 059a	D, 1
Lower internals assembly (lower core plate)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-289	3.1-1, 053c	B
Lower internals assembly (lower core plate)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Lower internals assembly (lower core plate)	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-288	3.1-1, 059c	D
Lower internals assembly (lower support forging)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-291a	3.1-1, 053b	B
Lower internals assembly (lower support forging)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Lower support assembly (lower support column bodies)	Structural support	Stainless steel	Reactor coolant Neutron flux	Changes in dimensions	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-274	3.1-1, 059b	D
Lower support assembly (lower support column bodies)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-291a	3.1-1, 053b	D
Lower support assembly (lower support column bodies)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Lower support assembly (lower support column bodies)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-290a	3.1-1, 059b	B
Lower support assembly (lower support column bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-286	3.1-1, 053b	B
Lower support assembly (lower support column bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Lower support assembly (lower support column bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Loss of preload	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-287	3.1-1, 059b	B
Lower support assembly (lower support column bolts)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-290b	3.1-1, 059b	D
No additional measures components	Structural support Flow distribution	Nickel alloy Stainless steel	Reactor coolant Neutron flux	None	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-265	3.1-1, 055c	B
Radial support keys	Structural support	Stellite	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	F
Radial support keys	Structural support	Stellite	Reactor coolant Neutron flux	Wear	Reactor Vessel Internals (B.2.3.7)	None	None	J, 3

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reactor vessel internal components with a fatigue analysis	Structural support	Cast austenitic stainless steel Nickel alloy Stainless steel	Reactor coolant Neutron flux	Cumulative fatigue damage	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.B2.RP-303	3.1-1, 003	B
Thermal shield assembly (thermal shield flexures)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-302	3.1-1, 053a	B
Upper core plate (fuel alignment pins)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-289	3.1-1, 053c	D
Upper core plate (fuel alignment pins)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-288	3.1-1, 059c	D
Upper internals assembly (upper core plate)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B2.RP-291b	3.1-1, 053b	B
Upper internals assembly (upper core plate)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.B2.RP-382	3.1-1, 032	A
Upper internals assembly (upper core plate)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B2.RP-295	3.1-1, 059b	D

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes

1. Component inspection category is not consistent with the inspection category cited in Table 3.1-1.
2. The PWR Vessel Internals program manages loss of fracture toughness and changes in dimension for stainless steel flux thimble tubes through FMECA analysis described further in Appendix C. Loss of preload is not applicable to flux thimble tubes, and loss of material is addressed by NUREG-2191 item IV.B2.RP-284. Flux thimble tubes are existing program components.
3. Wear surfaces for the upper core plate alignment pins, clevis inserts, and radial support keys are Stellite. Aging effects identified in the Appendix C RVI gap analysis for these components are managed by the Reactor Vessel Internals program.

Table 3.1.2-3: Pressurizers – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heater well and sheath	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Heater well and sheath	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Heater well and sheath	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.R-217	3.1-1, 033	A B
Heater well and sheath	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.R-25	3.1-1, 042	A B
Heater well and sheath	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-58	3.1-1, 040	A
Heater well and sheath	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Manway cover	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C

Table 3.1.2-3: Pressurizers – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Manway cover	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.R-25	3.1-1, 042	A B
Manway cover	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-58	3.1-1, 040	A
Manway cover	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Manway cover bolts	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	IV.C2.RP- 166	3.1-1, 064	A
Manway cover bolts	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	IV.C2.R-12	3.1-1, 066	A
Pressurizer components subject to fatigue	Pressure boundary	Carbon steel with stainless steel clad Stainless steel	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.C2.R-223	3.1-1, 009	A
Pressurizer components; heads, shell, nozzles	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Pressurizer components; heads, shell, nozzles	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-58	3.1-1, 040	A

Table 3.1.2-3: Pressurizers – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer components; heads, shell, nozzles	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.R-25	3.1-1, 042	A B
Pressurizer components; heads, shell, nozzles	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Safe ends, instrument nozzles, thermowells	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Safe ends, instrument nozzles, thermowells	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Safe ends, instrument nozzles, thermowells	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-58	3.1-1, 040	A
Safe ends, instrument nozzles, thermowells	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.R-25	3.1-1, 042	A B
Safe ends, instrument nozzles, thermowells	Pressure boundary	Stainless steel	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Steel components	Pressure boundary	Steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.C2.R-17	3.1-1, 049	A

Table 3.1.2-3: Pressurizers – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Steel components	Structural support	Steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.C2.R-17	3.1-1, 049	A
Support skirt and flange	Structural support	Carbon steel	Air – indoor uncontrolled (ext)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-19	3.1-1, 036	A
Support skirt and flange	Structural support	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Thermal sleeves	Insulate (thermal)	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.R-25	3.1-1, 042	A B

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.1.2-4: Reactor Coolant and Connected Piping – Summary of Aging Management Evaluation

Table 3.1.2-4: Reactor Coolant and Connected Piping – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	IV.C2.RP-166	3.1-1, 064	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	IV.C2.R-12	3.1-1, 066	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	IV.C2.R-11	3.1-1, 062	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	IV.C2.RP-166	3.1-1, 064	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	IV.C2.R-12	3.1-1, 066	A
Bolting; piping and piping components	Mechanical closure	Carbon steel Stainless steel	Air – indoor uncontrolled (ext)	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.C2.R-18	3.1-1, 005	A
Bolting; pump and valve	Mechanical closure	Carbon steel Stainless steel	Air – indoor uncontrolled (ext)	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.C2.RP-44	3.1-1, 011	A
Class 1 piping and piping components < 4" NPS	Pressure boundary	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2) ASME Code Class 1 Small-Bore Piping (B.2.3.22)	IV.C2.RP-235	3.1-1, 039	A B A

Table 3.1.2-4: Reactor Coolant and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flow indicators	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Flow indicators	Pressure boundary	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.RP-344	3.1-1, 033	A B
Flow indicators	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Heat exchanger (RCP thermal barrier coil)	Pressure boundary	Stainless steel	Reactor coolant (ext)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.RP-344	3.1-1, 033	C D
Heat exchanger (RCP thermal barrier coil)	Pressure boundary	Stainless steel	Reactor coolant (ext)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	D
Heat exchanger (RCP thermal barrier coil)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Orifice	Pressure boundary	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.RP-344	3.1-1, 033	A B

Table 3.1.2-4: Reactor Coolant and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Orifice	Throttle	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Orifice	Throttle	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Orifice	Throttle	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.RP-344	3.1-1, 033	A B
Orifice	Throttle	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Piping and piping components	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Piping and piping components	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Piping and piping components	Pressure boundary	CASS	Reactor coolant (int)	Cracking	Water Chemistry (B.2.3.2)	IV.C2.R-05	3.1-1, 020	E, 1
Piping and piping components	Pressure boundary	CASS	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-56	3.1-1, 035	A
Piping and piping components	Pressure boundary	CASS	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B

Table 3.1.2-4: Reactor Coolant and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Pressure boundary	CASS	Reactor coolant >482°F (int)	Loss of fracture toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B.2.3.6)	IV.C2.R-52	3.1-1, 050	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Piping and piping components	Pressure boundary	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.RP-344	3.1-1, 033	A B
Piping and piping components	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Piping and piping components	Pressure boundary	Steel Stainless steel CASS	Reactor coolant (int)	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.C2.R-18	3.1-1, 005	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.RP-344	3.1-1, 033	A B

Table 3.1.2-4: Reactor Coolant and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Pressurizer relief tank	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-451c	3.2-1, 108	A
Pressurizer relief tank	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-442b	3.2-1, 099	A
Pressurizer relief tank	Pressure boundary	Stainless steel	Condensation (int)	Cracking	One-Time Inspection (B.2.3.20)	V.A.EP-103b	3.2-1, 007	A
Pressurizer relief tank	Pressure boundary	Stainless steel	Condensation (int)	Loss of material	One-Time Inspection (B.2.3.20)	IV.C2.R-452a	3.1-1, 136	C
Pressurizer relief tank	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Pressurizer relief tank	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C2.RP-383	3.1-1, 080	B A
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Pump casing	Pressure boundary	CASS	Reactor coolant (int)	Cracking	Water Chemistry (B.2.3.2)	IV.C2.R-05	3.1-1, 020	E, 1
Pump casing	Pressure boundary	CASS	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-56	3.1-1, 035	A

Table 3.1.2-4: Reactor Coolant and Connected Piping – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	CASS	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Pump casing	Pressure boundary	CASS	Reactor coolant >482°F (int)	Loss of fracture toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B.2.3.6)	IV.C2.R-52	3.1-1, 050	A
Pump casing (thermal barrier flange and main flange)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Pump casing (thermal barrier flange and main flange)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Pump casing (thermal barrier flange and main flange)	Pressure boundary	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.R-09	3.1-1, 033	A B
Pump casing (thermal barrier flange and main flange)	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Pump casing (thermal barrier flange and main flange)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Steel components	Pressure boundary	Steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.C2.R-17	3.1-1, 049	A

Table 3.1.2-4: Reactor Coolant and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Thermowell	Pressure boundary	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.RP-344	3.1-1, 033	A B
Thermowell	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Valve body	Pressure boundary	CASS	Reactor coolant (int)	Cracking	Water Chemistry (B.2.3.2)	IV.C2.R-05	3.1-1, 020	E, 1
Valve body	Pressure boundary	CASS	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-56	3.1-1, 035	A
Valve body	Pressure boundary	CASS	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Valve body	Pressure boundary	CASS	Reactor coolant >482°F (int)	Loss of fracture toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-08	3.1-1, 038	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A

Table 3.1.2-4: Reactor Coolant and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.C2.R-09	3.1-1, 033	A B
Valve body	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	D

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

Plant Specific Notes

1. Per Section 3.1.2.2.6.2, cracking due to SCC in Class 1 RCS components is managed by the Water Chemistry (B.2.3.2) AMP.

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Anti-vibration bars	Structural support	Chrome-plated Alloy 600 (U1)	Treated water >140°F Steam	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	B
Anti-vibration bars	Structural support	Chrome-plated Alloy 600 (U1)	Treated water Steam	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	B
Anti-vibration bars	Structural support	Chrome-plated Alloy 600 (U1)	Treated water Steam	Loss of material	Steam Generators (B.2.3.10)	IV.D1.RP-225	3.1-1, 076	B
Anti-vibration bars	Structural support	Stainless steel (U2)	Treated water >140°F Steam	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	B
Anti-vibration bars	Structural support	Stainless steel (U2)	Treated water Steam	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	B
Anti-vibration bars	Structural support	Stainless steel (U2)	Treated water Steam	Loss of material	Steam Generators (B.2.3.10)	IV.D1.RP-225	3.1-1, 076	B
Blowdown piping nozzles and secondary side shell penetrations	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	A
Blowdown piping nozzles and secondary side shell penetrations	Pressure boundary	Carbon steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.D1.R-17	3.1-1, 049	A

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Blowdown piping nozzles and secondary side shell penetrations	Pressure boundary	Carbon steel	Treated water	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.D1.RP-368	3.1-1, 012	C D
Channel head drain coupling and Alloy 52/152 weld filler (U1)	Pressure boundary	Nickel alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-452b	3.1-1, 136	A
Channel head drain coupling and Alloy 52/152 weld filler (U1)	Pressure boundary	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Channel head with primary nozzles	Pressure boundary	Carbon steel with stainless steel clad	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Channel head with primary nozzles	Pressure boundary	Carbon steel with stainless steel clad	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.D1.R-17	3.1-1, 049	A
Channel head with primary nozzles	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.D1.RP-232	3.1-1, 033	C D
Channel head with primary nozzles	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-436	3.1-1, 127	B
Channel head with primary nozzles	Pressure boundary	Carbon steel with stainless steel clad	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Divider plate	Direct flow	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	D
Divider plate (U1)	Direct flow	Nickel alloy	Reactor coolant	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.D1.RP-367	3.1-1, 025	B B E, 1
Divider plate (U2)	Direct flow	Nickel alloy	Reactor coolant	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-367	3.1-1, 025	B
Feedwater feedring and support structure	Structural integrity (attached)	Carbon steel (U1)	Treated water >140°F Steam	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	D
Feedwater feedring and support structure	Structural integrity (attached)	Carbon steel (U1)	Treated water Steam	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	D
Feedwater feedring and support structure	Structural integrity (attached)	Carbon steel (U1)	Treated water Steam	Wall thinning – FAC	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-49	3.1-1, 074	D
Feedwater feedring and support structure	Structural integrity (attached)	Low-alloy steel (U2)	Treated water >140°F Steam	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	D
Feedwater feedring and support structure	Structural integrity (attached)	Low-alloy steel (U2)	Treated water Steam	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	D

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Feedwater j-nozzle	Structural integrity (attached)	Nickel alloy	Treated water >140°F Steam	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	D
Feedwater j-nozzle	Structural integrity (attached)	Nickel alloy	Treated water Steam	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	D
Feedwater nozzle	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	A
Feedwater nozzle	Pressure boundary	Carbon steel	Treated water	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.D1.RP-368	3.1-1, 012	C D
Feedwater nozzle	Pressure boundary	Carbon steel	Treated water	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	IV.D1.R-37	3.1-1, 061	A
Lower shell	Pressure boundary	Carbon steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.D1.R-17	3.1-1, 049	A
Moisture separators	Direct flow	Carbon steel	Treated water Steam	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-161	3.1-1, 072	D
Moisture separators	Direct flow	Carbon steel	Treated water Steam	Wall thinning – FAC	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-49	3.1-1, 074	B
Moisture separators	Direct flow	Nickel alloy	Treated water >140°F Steam	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	D

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Moisture separators	Direct flow	Nickel alloy	Treated water Steam	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	D
Moisture separators	Direct flow	Stainless steel	Treated water >140°F Steam	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	D
Moisture separators	Direct flow	Stainless steel	Treated water Steam	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	D
Primary manway bolting	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	IV.D1.RP-166	3.1-1, 064	A
Primary manway bolting	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	IV.D1.RP-46	3.1-1, 067	A
Primary manway bolting	Pressure boundary	Low-alloy steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.C2.RP-167	3.1-1, 049	A
Primary manway cover	Pressure boundary	Carbon steel with stainless steel insert	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Primary manway cover	Pressure boundary	Carbon steel with stainless steel insert	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.D1.R-17	3.1-1, 049	A
Primary manway cover	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.D1.RP-232	3.1-1, 033	A B

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Primary manway cover	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	D
Primary nozzle safe end Alloy 82/182 welds (U2)	Pressure boundary	Nickel alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-452b	3.1-1, 136	A
Primary nozzle safe end Alloy 82/182 welds (U2)	Pressure boundary	Nickel alloy	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2) Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in RCPB Components (B.2.3.5)	IV.D1.RP-36	3.1-1, 045	A B A
Primary nozzle safe end Alloy 82/182 welds (U2)	Pressure boundary	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Primary nozzle safe ends	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Primary nozzle safe ends	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-452b	3.1-1, 136	A
Primary nozzle safe ends	Pressure boundary	Stainless steel	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.D1.RP-232	3.1-1, 033	A B

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Primary side Alloy 690 vent nozzles (U2)	Pressure boundary	Nickel alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-452b	3.1-1, 136	A
Primary side Alloy 690 vent nozzles (U2)	Pressure boundary	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
Secondary closure bolting (excluding U1 inspection port)	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	IV.D1.RP-166	3.1-1, 064	A
Secondary closure bolting (excluding U1 inspection port)	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	IV.D1.RP-46	3.1-1, 067	A
Secondary closure bolting (excluding U1 inspection port)	Pressure boundary	Low-alloy steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.C2.RP-167	3.1-1, 049	A
Secondary closure bolting (excluding U1 inspection port)	Pressure boundary	Nickel alloy	Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2) Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in RCPB Components (B.2.3.5)	IV.D1.RP-36	3.1-1, 045	A B A
Secondary closures	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Secondary closures	Pressure boundary	Carbon steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.D1.R-17	3.1-1, 049	A

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Secondary closures	Pressure boundary	Carbon steel	Treated water	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.D1.RP-368	3.1-1, 012	C D
Secondary closures	Pressure boundary	Carbon steel	Treated water	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.D1.R-31	3.1-1, 044	A
Seismic lugs	Structural support	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Steam flow limiter	Throttle	Nickel alloy	Steam	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	D
Steam flow limiter	Throttle	Nickel alloy	Steam	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	D
Steam generator components with fatigue analysis	Pressure boundary	Carbon steel	Treated water Steam	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.D1.R-33	3.1-1, 005	A
Steam generator components with fatigue analysis	Pressure boundary	Carbon steel with stainless steel clad Nickel alloy Stainless steel	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.D1.R-221	3.1-1, 008	A
Steam outlet nozzle	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	A

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steam outlet nozzle	Pressure boundary	Carbon steel	Steam	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.D1.RP-368	3.1-1, 012	C D
Steam outlet nozzle	Pressure boundary	Carbon steel	Steam	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	IV.D1.R-37	3.1-1, 061	A
Support pads	Structural support	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Support pads	Structural support	Carbon steel	Air with borated water leakage (ext)	Loss of material	Boric Acid Corrosion (B.2.3.4)	IV.D1.R-17	3.1-1, 049	A
Transition cone	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C
Transition cone weld (U1 original)	Pressure boundary	Carbon steel	Treated water	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.D1.RP-368	3.1-1, 012	A B
Transition cone welds (new welds)	Pressure boundary	Carbon steel	Treated water	Loss of material	ASME Section XI Inservice Inspection, IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.D1.RP-368	3.1-1, 012	A B E, 2
Tube bundle wrapper and wrapper support system	Direct flow Structural support	Carbon steel	Treated water Steam	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-161	3.1-1, 072	B

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tube plugs	Pressure boundary	Nickel alloy	Reactor coolant	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-40	3.1-1, 070	B
Tube plugs	Pressure boundary	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	D
Tube support plates	Structural support	Stainless steel	Treated water >140°F Steam	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	B
Tube support plates	Structural support	Stainless steel	Treated water Steam	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	B
Tube support plates	Structural support	Stainless steel	Treated water Steam	Loss of material	Steam Generators (B.2.3.10)	IV.D1.RP-225	3.1-1, 076	B
Tubesheet	Pressure boundary	Carbon steel	Treated water	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-161	3.1-1, 072	D
Tubesheet	Pressure boundary	Carbon steel with nickel alloy clad	Reactor coolant	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-436	3.1-1, 127	B
Tube-to-tubesheet weld (U2)	Pressure boundary	Nickel alloy	Reactor coolant	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-385	3.1-1, 025	B
Tube-to-tubesheet weld (U2)	Pressure boundary	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	D
Upper and lower shell, elliptical head and transition cone	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C2.R-431	3.1-1, 124	C

Table 3.1.2-5: Steam Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Upper and lower shell, elliptical head and transition cone	Pressure boundary	Carbon steel	Treated water	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.D1.RP-368	3.1-1, 012	A B
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Reactor coolant	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-44	3.1-1, 070	B
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Reactor coolant	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.D1.R-46	3.1-1, 002	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Reactor coolant	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	B
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water >140°F Steam	Cracking	Steam Generators (B.2.3.10)	IV.D1.R-437	3.1-1, 125	B
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water >140°F Steam	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-47	3.1-1, 069	B
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water Steam	Loss of material	Steam Generators (B.2.3.10)	IV.D1.RP-233	3.1-1, 077	B
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water Steam	Reduction of heat transfer	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-407	3.1-1, 111	B

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

Plant Specific Notes

1. Per Section 3.1.2.2.11, the Unit 1 divider plate aging effect of cracking is managed by the Steam Generators (B.2.3.10), Water Chemistry (B.2.3.2), and One-Time Inspection (B.2.3.20) AMPs.

3.2. AGING MANAGEMENT OF ENGINEERED SAFETY FEATURES

3.2.1. Introduction

This section provides the results of the AMR for those components identified in Section 2.3.2, Engineered Safety Features, as being subject to AMR. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Safety Injection (2.3.2.1)
- Containment Spray (2.3.2.2)
- Residual Heat Removal (2.3.2.3)
- Containment Isolation Components (2.3.2.4)

3.2.2. Results

The following tables summarize the results of the AMR for Engineered Safety Features.

Table 3.2.2-1 Safety Injection - Summary of Aging Management Evaluation

Table 3.2.2-2 Containment Spray - Summary of Aging Management Evaluation

Table 3.2.2-3 Residual Heat Removal - Summary of Aging Management Evaluation

Table 3.2.2-4 Containment Isolation - Summary of Aging Management Evaluation

3.2.2.1. Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.2.2.1.1 Safety Injection

Materials

The materials of construction for the safety injection system components are:

- Carbon steel
- Carbon steel with stainless steel cladding
- CASS
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environments

The safety injection system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Gas
- Lubricating oil
- Treated borated water
- Treated borated water >140°F
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the safety injection system require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the safety injection system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Lubricating Oil Analysis (B.2.3.26)
- One-Time Inspection (B.2.3.20)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.2.2.1.2 Containment Spray

Materials

The materials of construction for the containment spray system components are:

- Carbon steel
- Carbon steel with stainless steel cladding
- CASS
- Glass
- Grey Cast Iron
- Stainless steel
- Steel

Environments

The containment spray system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated borated water
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the containment spray system require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the containment spray system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)

- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.2.2.1.3 Residual Heat Removal

Materials

The materials of construction for the residual heat removal system components are:

- Carbon steel
- CASS
- Gray cast iron
- Stainless steel
- Steel

Environments

The residual heat removal system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Hydraulic oil
- Treated borated water
- Treated borated water >140°F
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the residual heat removal system require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the residual heat removal system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- Lubricating Oil Analysis (B.2.3.26)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.2.2.1.4 Containment Isolation Components

Materials

The materials of construction for the containment isolation components system components are:

- Carbon steel
- CASS
- Stainless steel

Environments

The containment isolation components system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the containment isolation components system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the containment isolation components system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.2.2.2. AMR Results for Which Further Evaluation is Recommended by the GALL Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Engineered Safety Features, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

3.2.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Cumulative fatigue damage of Engineered Safety Features components, as described in SRP-SLR Item 3.2.2.2.1, is addressed in Section 4.3.3, Metal Fatigue of Non-Class 1 Components.

3.2.2.2.2 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor stainless steel (SS) and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in *environments containing sufficient halides (e.g., chlorides) in the presence of moisture.*

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific operating experience (OE) and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion, and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of systems, structures, and components (SSCs), the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, a one-time inspection would be *conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.*

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALLSLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

There are no stainless steel tanks exposed to an outdoor air environment in the scope of subsequent license renewal at PBN. Insulated and non-insulated stainless steel bolting, piping, piping components, tanks, and heat exchanger components are exposed to an uncontrolled indoor air environment. There is no nickel alloy included in the Engineered Safety Features Systems. A review of PBN operating experience confirms halides are potentially present in both the indoor and outdoor environments at PBN. Additionally, insulated piping and components located indoors, particularly those in standby or periodically operated systems, could conservatively see an accumulation of contaminants from water intrusion through or beneath insulation. As such, all stainless steel components exposed to uncontrolled indoor in the Engineered Safety Features Systems are susceptible to loss of material due to pitting and crevice corrosion and require management via an appropriate program.

Consistent with the recommendation of NUREG-2191, loss of material of these components will be managed via the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17), External Surfaces Monitoring of Mechanical Components (B.2.3.23) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMPs. The exception to this is bolting, which is managed by the Bolting Integrity (B.2.3.9) AMP. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of loss of material will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Bolting Integrity (B.2.3.9), Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17), External Surfaces Monitoring of Mechanical Components (B.2.3.23) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMPs are described in sections B.2.3.9, B.2.3.17, B.2.3.23, and B.2.3.25 respectively.

3.2.2.2.3 <u>Loss of Material Due to General Corrosion and Flow Blockage Due to Fouling</u>

Loss of material due to general corrosion (as applicable) and flow blockage due to fouling for all materials can occur in the spray nozzles and flow orifices in the drywell and suppression chamber spray system exposed to air-indoor uncontrolled. This aging effect and mechanism will apply since the carbon steel piping upstream of the spray nozzles and flow orifices is occasionally wetted, even though the majority of the time this system is in standby. The wetting and drying of these components can accelerate corrosion in the system and lead to flow blockage from an accumulation of corrosion products. Aging effects sufficient to result in a loss of intended function are not anticipated if: (a) the *applicant identifies those portions of the system that are normally dry but subject to periodic wetting; (b) plant-specific procedures exist to drain the normally dry portions that have been wetted during normal plant operation or inadvertently; (c) the plant-specific configuration of the drains and piping allow sufficient draining to empty the normally dry pipe; (d) plant-specific OE has not revealed loss of material or flow blockage due to fouling; and (e) a one-time inspection is conducted to verify that loss of material or flow blockage due to fouling has not occurred. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to conduct the one-time inspections. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," describes an acceptable program to manage loss of material due to general corrosion and flow blockage due to fouling when the above conditions are not met.*

This item is not applicable to PBN as it only applies to drywell and suppression chamber spray nozzles in BWRs.

3.2.2.2.4 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to stress corrosion cracking (SCC) could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the SLRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable programs to manage loss of *material due to SCC: (a) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.*

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

There are no stainless steel components exposed to outdoor air in the Engineered Safety Features Systems. Insulated and non-insulated stainless steel bolting, piping, piping components, tanks and heat exchanger components are exposed to an uncontrolled indoor air environment. A review of PBN operating experience confirms halides are potentially present in the indoor environments at PBN. Additionally, insulated piping and components located indoors, particularly those in standby or periodically operated systems, could conservatively see an accumulation of contaminants from water intrusion through or beneath insulation. As such, all stainless steel components exposed to uncontrolled indoor air in the Engineered Safety Features Systems are susceptible to SCC and require management via an appropriate program.

Consistent with the recommendation of NUREG-2191, cracking of these components will be managed via the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17), External Surfaces Monitoring of Mechanical Components (B.2.3.23), and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMPs. The exception to this is bolting, which is managed by the Bolting Integrity (B.2.3.9) AMP. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Bolting Integrity (B.2.3.9), Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17), External Surfaces Monitoring of Mechanical Components (B.2.3.23), and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMPs are described in Sections B.2.3.9, B.2.3.17, B.2.3.23, and B.2.3.25, respectively.

3.2.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in Branch Technical Position (BTP) IQMB-1 (Appendix A.2 of this SRP-SLR).

Quality Assurance provisions applicable to subsequent license renewal are discussed in Section B.1.3.

3.2.2.2.6 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs."

The Operating Experience process and acceptance criteria are described in Section B.1.4

3.2.2.2.7 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant-specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant-specific OE reveals repetitive occurrences. The criteria for recurrence is (a) a 10-year search of plant-specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5-year search of plant-specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant-specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily *accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.*

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10-year search of plant-specific OE, two instances of a 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

PBN operating experience over the past 10 years shows no instances that meet the criteria of recurring internal corrosion for metals containing raw water, waste water, or treated water; therefore, recurring internal corrosion is not an applicable aging effect at PBN. There is no need to augment the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP due to recurring internal corrosion.

3.2.2.2.8 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of subsequent license renewal (SLR), acceptance criteria for this further evaluation are being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

Susceptible Material: If the material is not susceptible to SCC, then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*

- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

<u>Aggressive Environment</u>: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. The GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC *of aluminum piping and piping components. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks, which are buried or underground. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.*

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

As the Engineered Safety Features Systems do not contain any aluminum or aluminum alloy components, cracking of aluminum alloys is not an applicable aging effect.

3.2.2.2.9 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice or pitting corrosion and *cracking due to SCC (SS only) are identified as applicable aging effects. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.*

Portions of the stainless steel piping in the Engineered Safety Features Systems are exposed to or encased in concrete. Stainless steel piping in the Engineered Safety Features Systems that is exposed to concrete is not susceptible to being exposed to groundwater and therefore has no aging effects that require management. There is no steel piping exposed to a concrete environment in the Engineered Safety Features Systems. The concrete is managed by ASME Section XI, Subsection IWL (B.2.3.30) or Structures Monitoring (B.2.3.34) AMPs.

Consistent with the recommendation of NUREG-2191, the stainless steel piping exposed to concrete and not exposed to groundwater does not have any external aging effects; therefore, there are no aging management programs associated with the management of these components.

3.2.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or wastewater environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy *susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.*

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

As the Engineered Safety Features Systems do not contain any aluminum or aluminum alloy components, loss of material of aluminum alloys is not an applicable aging effect.

3.2.2.3. Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Engineered Safety Features components:

- Section 4.3, Metal Fatigue

3.2.3. Conclusion

The Engineered Safety Features piping, fittings, and components that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Engineered Safety Features System components are identified in the summaries in Section 3.2.2 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Engineered Safety Features components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the CLB during the SPEO.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 001	Stainless steel, steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.2.2.2.1)	Cumulative fatigue damage is an aging effect assessed by a fatigue TLAA. Further evaluation is documented in subsection 3.2.2.2.1.
3.2-1, 004	Stainless steel, nickel alloy piping, piping components exposed to air, condensation (external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191 for component types listed but is also used for stainless steel heat exchanger components. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP will be used to manage loss of material of stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air. Further evaluation is documented in subsection 3.2.2.2.2.
3.2-1, 005	Stainless steel orifice (miniflow recirculation when centrifugal HPSI pumps are used for normal charging) exposed to treated borated water	Loss of material due to erosion	AMP XI.M32, "One-Time Inspection"	No	Not used. The Safety Injection (SI) pumps are not used for normal charging and the stainless steel orifices in these systems are not subjected to high-velocity flow during normal operation.
3.2-1, 006	This line item only applies to BWRs.				

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 007	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191 for component types listed but is also used for CASS piping components including the Reactor Coolant and Connected Piping Systems and stainless steel heat exchanger components. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) and External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMPs are used to manage cracking of stainless steel and CASS piping, piping components, and heat exchanger components exposed to air internally and externally, respectively. Line item 3.2-1, 103 is used to manage cracking of the refueling water storage tanks. Further evaluation is documented in subsection 3.2.2.2.4. This line item is also used to manage the pressurizer relief tanks. The One-Time Inspection (B.2.3.20) AMP is used to ensure no cracking due to SCC of stainless steel tanks exposed to condensation in the section of the tank filled with nitrogen.
3.2-1, 008	Copper alloy (>15% Zn) piping, piping components exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Not applicable. There is no copper alloy >15% Zn piping or piping components exposed to air with borated water leakage in the Engineered Safety Features Systems.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 009	Steel external surfaces exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Consistent with NUREG-2191. The Boric Acid Corrosion (B.2.3.4) AMP is used to manage loss of material of steel surfaces exposed to air with borated water leakage.
3.2-1, 010	Cast austenitic stainless steel piping, piping components exposed to treated borated water >250°C (>482°F), treated water >250°C (>482°F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless steel (CASS)"	No	Not applicable. The only CASS components exposed to treated borated water with temperatures greater than 250°C (482°F) are part of the reactor coolant pressure boundary and are evaluated as part of the Reactor Coolant system.
3.2-1, 011	Steel piping, piping components exposed to steam, treated water	Wall thinning due to flow- accelerated corrosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Not applicable. None of the Engineered Safety Features Systems are identified as susceptible to flow accelerated corrosion (FAC) in PBN's FAC program.
3.2-1, 012	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, "Bolting Integrity"	No	Not applicable. There is no high-strength steel closure bolting in the Engineered Safety Features Systems.
3.2-1, 014	Stainless steel, steel, nickel alloy closure bolting exposed to air- indoor uncontrolled, air-outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage loss of material of stainless steel and steel closure bolting exposed to uncontrolled air environments.
3.2-1, 015	Metallic closure bolting exposed to any environment, soil underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage loss of preload of metallic closure bolting in any environment.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 016	Steel piping, piping components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not used. While steel exposed to treated water is present in the Engineered Safety Features systems, this treated water is closed cooling water.
3.2-1, 017	Aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no aluminum piping or piping components in the Engineered Safety Features Systems.
3.2-1, 019	Stainless steel heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage reduction of heat transfer of stainless steel heat exchanger tubes exposed to treated borated water. In addition, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP performs eddy current testing on the residual heat removal heat exchangers.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 020	Stainless steel, steel (with stainless steel or nickel alloy cladding) piping, piping components, tanks exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. This line item is also used for stainless steel heat exchanger components. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage cracking of stainless steel heat exchangers, piping, and piping components exposed to treated borated water >60°C (>140°F).
3.2-1, 022	Nickel alloy, stainless steel heat exchanger components, piping, piping components, tanks exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. It is also used for carbon steel tanks clad with stainless steel and the pressurizer relief tank. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel heat exchanger components, piping, and piping components and carbon steel with stainless steel cladding tanks exposed to treated water or treated borated water. In addition, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP performs eddy current testing on the residual heat removal heat exchanger tubes based on plant specific OE.
3.2-1, 023	Steel heat exchanger components, piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no steel components in the Engineered Safety Features Systems exposed to raw water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 024	Stainless steel piping, piping components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no stainless steel piping or components in the Engineered Safety Features Systems exposed to raw water.
3.2-1, 025	Stainless steel heat exchanger components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no stainless steel components in the Engineered Safety Features Systems exposed to raw water.
3.2-1, 027	Stainless steel, steel heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no steel or stainless steel components in the Engineered Safety Features Systems exposed to raw water
3.2-1, 028	Stainless steel piping, piping components exposed to closed- cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no stainless steel piping or piping components in the Engineered Safety Features Systems exposed to closed-cycle cooling water greater than 60°C (>140°F).
3.2-1, 029	Steel piping, piping components exposed to closed- cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no steel piping or piping components in the Engineered Safety Features Systems exposed to closed-cycle cooling water.
3.2-1, 030	Steel heat exchanger components exposed to closed- cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage loss of material in steel heat exchanger components exposed to treated water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 031	Stainless steel heat exchanger components, piping, piping components exposed to closed- cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception for the Closed Treated Water Systems (B.2.3.12) AMP. The Closed Treated Water Systems (B.2.3.12) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) (Residual Heat Removal System only) AMPs are used to manage loss of material in stainless steel heat exchanger components exposed to treated water.
3.2-1, 032	Copper alloy heat exchanger components, piping, piping components exposed to closed- cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no copper alloy heat exchanger components or piping or piping components in the Engineered Safety Features Systems exposed to closed-cycle cooling water.
3.2-1, 033	Copper alloy, stainless steel heat exchanger tubes exposed to closed- cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception for the Closed Treated Water Systems (B.2.3.12) AMP. The Closed Treated Water Systems (B.2.3.12) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) (Residual Heat Removal System only) AMPs are used to manage reduction of heat transfer in stainless steel heat exchanger tubes exposed to treated water. This also applied to heat exchanger tubes in the Auxiliary System.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 034	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed- cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no copper alloy (>15% Zn or >8% Al) heat exchanger components or piping or piping components in the Engineered Safety Features Systems exposed to closed-cycle cooling water or treated water.
3.2-1, 035	Gray cast iron motor cooler exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Consistent with NUREG-2191. This line item is used to heat exchanger components. The Selective Leaching (B.2.3.21) AMP is used to manage loss of material due to selective leaching in gray cast iron heat exchangers exposed to treated water.
3.2-1, 036	Gray cast iron, ductile iron piping, piping components exposed to closed- cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no gray cast iron or ductile iron piping or piping components in the Engineered Safety Features Systems.
3.2-1, 037	Gray cast iron, ductile iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no gray cast iron or ductile iron piping or piping components in the Engineered Safety Features Systems.
3.2-1, 038	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no elastomer piping, piping components, or seals in the Engineered Safety Features Systems.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 040	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material in steel external surfaces exposed to uncontrolled indoor air.
3.2-1, 042	Aluminum piping, piping components, tanks exposed to air, condensation (external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. There are no aluminum piping, piping components or tanks in the Engineered Safety Features Systems.
3.2-1, 043	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no elastomer piping, piping components, or seals in the Engineered Safety Features Systems.
3.2-1, 044	Steel piping, piping components, ducting, ducting components exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. This line item is also used for tanks. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage loss of material internal to steel piping, piping components, ducting, and ducting components exposed to uncontrolled indoor air.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 045	Steel encapsulation components exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel encapsulation components exposed to uncontrolled indoor air in the Engineered Safety Features Systems. Penetration Assemblies for the RHR recirculation lines are addressed in Table 3.5.2-1 with other mechanical penetrations.
3.2-1, 046	Steel piping, piping components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel piping components exposed to condensation in the Engineered Safety Features Systems.
3.2-1, 047	Steel encapsulation components exposed to air with borated water leakage	Loss of material due to general, pitting, crevice, boric acid corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel encapsulation components exposed to air with borated water leakage in the Engineered Safety Features Systems. Penetration Assemblies for the RHR recirculation lines are addressed in Table 3.5.2-1 with other mechanical penetrations.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 048	Stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation (internal)	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage loss of material of stainless steel piping and piping components exposed to air internally. Further evaluation is documented in subsection 3.2.2.2.2.
3.2-1, 049	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.26) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel piping and piping components exposed to lubricating oil and hydraulic oil .
3.2-1, 050	Copper alloy, stainless steel piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.26) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel piping and piping components exposed to hydraulic oil.
3.2-1, 051	Steel, copper alloy, stainless steel heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. The Engineered Safety Features Systems does not include any steel, copper alloy, or stainless steel heat exchanger tubes exposed to lubricating oil.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 052	Steel piping, piping components exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. The Engineered Safety Features Systems does not include any buried or underground steel piping or tanks.
3.2-1, 053	Stainless steel, nickel alloy piping, piping components, tanks, exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. The Engineered Safety Features Systems does not include any buried or underground piping or tanks exposed to soil or concrete. Stainless steel piping encased in concrete is covered by line item 3.2-1, 091.
3.2-1, 054	This line item only applies to BWRs.				
3.2-1, 055	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Not applicable. There are no steel piping or piping components exposed to concrete in the Engineered Safety Features Systems.
3.2-1, 056	Aluminum piping, piping components, tanks exposed to air, condensation (internal)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP-XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. There are no aluminum piping, piping components, or tanks in the Engineered Safety Features Systems.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 057	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Not applicable. There are no copper alloy piping, piping components, and heat exchanger components in the Engineered Safety Features Systems.
3.2-1, 058	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not used. There are no copper alloy or copper alloy >8% Al piping and piping components exposed to air with borated water leakage in the Engineered Safety Features Systems.
3.2-1, 059	Galvanized steel ducting, ducting components, piping, piping components exposed to air – indoor controlled	None	None	No	Not applicable. There are no galvanized steel ducting, ducting components, piping, or piping components exposed to air in the Engineered Safety Features Systems.
3.2-1, 060	Glass piping elements exposed to air, underground, lubricating oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, closed-cycle cooling water	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for glass piping elements exposed to treated borated water, air with borated water leakage, or air.
3.2-1, 062	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. The Engineered Safety Features Systems do not include any nickel alloy piping or piping components exposed to air with borated water leakage.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 063	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191. Stainless steel piping and piping components exposed to gas do not have any aging effects that require management. While the environment and material combination do exist, the environment of air with borated water leakage is only considered for steel components.
3.2-1, 064	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191. This line item is used to recognize the lack of aging effects in steel components exposed to gas.
3.2-1, 065	Metallic piping, piping components exposed to treated water, treated borated water	Wall thinning due to erosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Not applicable. There are no metallic piping, or piping components in the Engineered Safety Features Systems exposed to treated water or treated borated water susceptible to erosion
3.2-1, 066	Metallic piping, piping components, tanks exposed to raw water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.2.2.2.7)	Not applicable. There are no components in the Engineered Safety Features Systems exposed to raw water or waste water. Based on a review of PBN OE, there are no instances of recurring internal corrosion in the Engineered Safety Features Systems.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 067	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage cracking of the stainless steel refueling water storage tanks exposed to concrete.
3.2-1, 068	Steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. The Engineered Safety Features Systems do not include steel tanks exposed to soil, concrete, air, or condensation within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP.
3.2-1, 069	Insulated steel piping, piping components, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. The Engineered Safety Features Systems do not include any insulated steel piping, piping components, or tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP.
3.2-1, 070	Steel, stainless steel, aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water, treated borated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material of the stainless steel refueling water storage tanks exposed to treated borated water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 071	Insulated copper alloy (>15% Zn or >8% Al) piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no insulated copper alloy piping components in the Engineered Safety Features Systems.
3.2-1, 072	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed- cycle cooling water, raw water, treated water, treated borated water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. The Engineered Safety Features Systems do not include any material piping, piping components, heat exchangers, or tanks with internal coatings/linings exposed to closed- cycle cooling water, raw water, treated water, or treated borated water.
3.2-1, 073	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed- cycle cooling water, raw water, treated water, treated borated water, lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. The Engineered Safety Features Systems do not include any material piping, piping components, heat exchangers, or tanks with internal coatings/linings exposed to closed- cycle cooling water, raw water, treated water, or treated borated water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 074	Gray cast iron, ductile iron piping, piping components with internal coatings/linings exposed to closed- cycle cooling water, raw water, treated water, treated borated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. The Engineered Safety Features Systems do not include any material piping, piping components, heat exchangers, or tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, or treated borated water.
3.2-1, 076	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to treated water, treated borated water, raw water, waste water, lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC (steel, copper alloy in raw water, waste water only)	AMP XI.M18, "Bolting Integrity"	No	Not applicable The Engineered Safety Features Systems do not contain any bolting exposed to treated water, treated borated water, raw water, waste water, or lubricating oil.
3.2-1, 078	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. The Engineered Safety Features Systems do not include any steel, stainless steel, or aluminum piping or piping components with applicable aging effects. The Refueling Water Storage Tanks sit above-ground on concrete and are addressed by item 3.2-1, 067.
3.2-1, 079	Stainless steel closure bolting exposed to air, soil, concrete, underground	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage cracking of stainless steel closure bolting exposed to air.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 080	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Not applicable. The Engineered Safety Features Systems do not include any stainless steel underground piping, piping components, or tanks. See Section 3.2.2.2.4 for further evaluation.
3.2-1, 081	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. The Engineered Safety Features Systems do not include any stainless steel, steel, aluminum, copper alloy, or titanium heat exchanger tubes exposed to air, or condensation
3.2-1, 087	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There is no non-metallic insulation in the Engineered Safety Features subject to AMR.
3.2-1, 090	Steel components exposed to treated water, treated borated water, raw water	Long-term loss of material due to general corrosion	AMP XI.M32, "One Time Inspection"	No	Not applicable. The Engineered Safety Features Systems do not include any steel components exposed to treated borated water or raw water that are susceptible to long-term loss of material because corrosion inhibitors are used. Line item 3.2-1, 030 is used for steel heat exchanger shells exposed to treated water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 091	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Consistent with NUREG-2191. As the stainless steel piping exposed to concrete in the Engineered Safety Features Systems is not also exposed to ground water, there are no aging effects that require management. Further evaluation is documented in subsection 3.2.2.2.9.
3.2-1, 096	Steel, stainless steel piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. The Engineered Safety Features Systems do not include stainless steel piping or piping components exposed to raw water.
3.2-1, 098	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. The Engineered Safety Features Systems do not include copper alloy piping or piping components exposed to soil.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 099	Stainless steel, nickel alloy tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. This line item is used for the stainless steel pressurizer relief tanks. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material. Further evaluation is documented in subsection 3.2.2.2.8.
3.2-1, 100	Aluminum piping, piping components, tanks exposed to air, condensation (internal), raw water, waste water	Cracking due to SCC	AMP XI.M32, "One Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. The Engineered Safety Features Systems do not include any aluminum piping, piping components, or tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 101	Aluminum piping, piping components, tanks exposed to air, condensation (external)	Cracking due to SCC	AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. The Engineered Safety Features Systems do not include any aluminum piping, piping components or tanks.
3.2-1, 102	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. The Engineered Safety Features Systems do not include any aluminum tanks.
3.2-1, 103	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to Manage cracking of the stainless steel refueling water storage tanks exposed to uncontrolled air. Further evaluation is documented in subsection 3.2.2.2.4.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 104	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. The Engineered Safety Features Systems do not include any aluminum tanks.
3.2-1, 105	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. The Engineered Safety Features Systems do not include any aluminum tanks.
3.2-1, 106	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material of the stainless steel refueling water storage tanks exposed to uncontrolled air. Further evaluation is documented in subsection 3.2.2.2.2.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 107	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material of insulated stainless steel piping exposed to air. Further evaluation is documented in subsection 3.2.2.2.2.
3.2-1, 108	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage cracking of insulated stainless steel piping and pressurizer relief tanks exposed to uncontrolled air. Further evaluation is documented in subsection 3.2.2.2.4.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 109	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. The Engineered Safety Features Systems do not include any insulated aluminum piping, piping components, or tanks.
3.2-1, 110	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. The Engineered Safety Features Systems do not include any aluminum piping, piping components, or tanks.
3.2-1, 111	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. The Engineered Safety Features Systems do not include any aluminum piping, piping components, or tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 112	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Not applicable. The Engineered Safety Features Systems do not include any stainless steel or nickel alloy underground piping, piping components, or tanks.
3.2-1, 114	Stainless steel, nickel alloy piping, piping components exposed to treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. The Engineered Safety Features Systems do not include any nickel alloy piping or piping components exposed to treated water >60°C (>140°F). Stainless steel components exposed to treated borated water are included in line item 3.2-1, 020.
3.2-1, 115	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. The Engineered Safety Features Systems do not include any titanium heat exchanger tubes.
3.2-1, 116	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not applicable. The Engineered Safety Features Systems do not include any titanium heat exchanger components, piping, or piping components.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 117	Titanium heat exchanger tubes exposed to closed- cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. The Engineered Safety Features Systems do not include any titanium heat exchanger tubes.
3.2-1, 118	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed- cycle cooling water	None	None	No	Not applicable. The Engineered Safety Features Systems do not include any titanium heat exchanger components, piping, or piping components.
3.2-1, 119	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. The Engineered Safety Features Systems do not include any insulated aluminum piping, piping components, or tanks.
3.2-1, 120	Aluminum piping, piping components, tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. The Engineered Safety Features Systems do not include any aluminum piping, piping components, or tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 121	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. The Engineered Safety Features Systems do not include any aluminum piping, piping components, or tanks.
3.2-1, 122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. The Engineered Safety Features Systems do not include any elastomer piping, piping components, or seals.
3.2-1, 123	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. The Engineered Safety Features Systems do not include any elastomer piping, piping components, or seals.
3.2-1, 124	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. The Engineered Safety Features Systems do not include any aluminum piping, piping components, or tanks.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 125	Steel closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. The Engineered Safety Features Systems do not include any steel closure bolts exposed to soil, concrete, or underground.
3.2-1, 126	Titanium, super austenitic piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to pitting, crevice corrosion, MIC (except for titanium; soil environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. The Engineered Safety Features Systems do not include any titanium or super austenitic piping, piping components, tanks, or closure bolting.
3.2-1, 127	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. The Engineered Safety Features Systems do not include any copper alloy piping or piping components exposed to concrete.
3.2-1, 128	Copper alloy piping, piping components exposed to soil, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. The Engineered Safety Features Systems do not include any copper alloy piping or piping components exposed to soil or underground.
3.2-1, 129	Stainless steel tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material of the stainless steel refueling water storage tanks exposed to concrete.
3.2-1, 130	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. The Engineered Safety Features Systems do not include any steel heat exchanger components exposed to lubricating oil.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 131	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. The Engineered Safety Features Systems do not include any aluminum piping or piping components.
3.2-1, 132	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. The Engineered Safety Features Systems do not include any titanium components.
3.2-1, 133	Titanium piping, piping components, heat exchanger components exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. The Engineered Safety Features Systems do not include any titanium components.
3.2-1, 134	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. The Engineered Safety Features Systems do not include any polymeric components.

Table 3.2.2-1: Safety Injection – Summary of Aging Management Evaluation

Table 3.2.2-1: Safety Injection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Accumulator	Pressure boundary	Carbon steel with stainless steel cladding	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Accumulator	Pressure boundary	Carbon steel with stainless steel cladding	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A
Accumulator	Pressure boundary	Carbon steel with stainless steel cladding	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	V.E.E-02	3.2-1, 014	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	V.E.EP-116	3.2-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	V.E.E-421	3.2-1, 079	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	V.E.E-02	3.2-1, 014	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	V.E.EP-116	3.2-1, 015	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A

Table 3.2.2-1: Safety Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Flow element	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (seal water case and cover)	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Heat exchanger (seal water case and cover)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-92	3.2-1, 030	B
Heat exchanger (seal water case and cover)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	V.D1.E-43	3.2-1, 035	A
Heat exchanger (seal water coil)	Heat transfer	Stainless steel	Treated borated water (int)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-20	3.2-1, 019	B A
Heat exchanger (seal water coil)	Heat transfer	Stainless steel	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-96	3.2-1, 033	B
Heat exchanger (seal water coil)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (seal water coil)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-93	3.2-1, 031	B

Table 3.2.2-1: Safety Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Instrument	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (ext)	None	None	V.F.EP-15	3.2-1, 060	A
Instrument	Leakage boundary (spatial)	Glass	Treated borated water (int)	None	None	V.F.EP-30	3.2-1, 060	A
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Instrument	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Instrument	Pressure boundary	Glass	Air – indoor uncontrolled (ext)	None	None	V.F.EP-15	3.2-1, 060	A
Instrument	Pressure boundary	Glass	Treated borated water (int)	None	None	V.F.EP-30	3.2-1, 060	A
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-1: Safety Injection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Instrument	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Instrument	Pressure boundary	Glass	Lubricating oil (int)	None	None	V.F.EP-16	3.2-1, 060	A
Level element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Level element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Level element	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Orifice	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A

Table 3.2.2-1: Safety Injection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Throttle	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Piping	Pressure boundary	Carbon steel	Gas (int)	None	None	V.F.EP-7	3.2-1, 064	A
Piping	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	V.D1.EP-77	3.2-1, 049	A

Table 3.2.2-1: Safety Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Piping	Pressure boundary	Stainless steel	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Piping	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-451c	3.2-1, 108	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-450c	3.2-1, 107	A
Piping and piping components	Pressure boundary	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	V.D1.E-13	3.2-1, 001	A

Table 3.2.2-1: Safety Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Gas (int)	None	None	V.F.EP-7	3.2-1, 064	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A

Table 3.2.2-1: Safety Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Pump casing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Steel components	Pressure boundary	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	V.E.E-28	3.2-1, 009	A
Tank (refueling water storage)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-446a	3.2-1, 103	A
Tank (refueling water storage)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-449a	3.2-1, 106	A
Tank (refueling water storage)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-446a	3.2-1, 103	A
Tank (refueling water storage)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-449a	3.2-1, 106	A
Tank (refueling water storage)	Pressure boundary	Stainless steel	Concrete (ext)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-405	3.2-1, 067	A
Tank (refueling water storage)	Pressure boundary	Stainless steel	Concrete (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-472	3.2-1, 129	A

Table 3.2.2-1: Safety Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank (refueling water storage)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-404	3.2-1, 070	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Valve body	Pressure boundary	Carbon steel	Gas (int)	None	None	V.F.EP-7	3.2-1, 064	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A

Table 3.2.2-1: Safety Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	CASS	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A
Valve body	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Valve body	Pressure boundary	CASS	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	Stainless steel	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Valve body	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.2.2-2: Containment Spray – Summary of Aging Management Evaluation

Table 3.2.2-2: Containment Spray – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	V.E.E-02	3.2-1, 014	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	V.E.EP-116	3.2-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	V.E.E-421	3.2-1, 079	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	V.E.E-02	3.2-1, 014	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	V.E.EP-116	3.2-1, 015	A
Eductor	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Eductor	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Eductor	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-2: Containment Spray – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Flow element	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Heat exchanger (containment spray pump seal water case and cover)	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Heat exchanger (containment spray pump seal water case and cover)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.A.EP-92	3.2-1, 030	B
Heat exchanger (containment spray pump seal water case and cover)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	V.A.E-43	3.2-1, 035	A
Heat exchanger (containment spray pump seal water coil)	Heat transfer	Stainless steel	Treated borated water (int)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.E-20	3.2-1, 019	B A
Heat exchanger (containment spray pump seal water coil)	Heat transfer	Stainless steel	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	V.A.EP-96	3.2-1, 033	B

Table 3.2.2-2: Containment Spray – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (containment spray pump seal water coil)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Heat exchanger (containment spray pump seal water coil)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.A.EP-93	3.2-1, 031	B
Instrument	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (ext)	None	None	V.F.EP-15	3.2-1, 060	A
Instrument	Leakage boundary (spatial)	Glass	Treated borated water (int)	None	None	V.F.EP-30	3.2-1, 060	A
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Instrument	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Instrument	Pressure boundary	Glass	Air – indoor uncontrolled (ext)	None	None	V.F.EP-15	3.2-1, 060	A
Instrument	Pressure boundary	Glass	Treated borated water (int)	None	None	V.F.EP-30	3.2-1, 060	A
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A

Table 3.2.2-2: Containment Spray – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Instrument	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Nozzle	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Nozzle	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Nozzle	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.EP-103d	3.2-1, 007	A
Nozzle	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.EP-81c	3.2-1, 048	A
Nozzle	Spray	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Nozzle	Spray	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-2: Containment Spray – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Nozzle	Spray	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.EP-103d	3.2-1, 007	A
Nozzle	Spray	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.EP-81c	3.2-1, 048	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Orifice	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Orifice	Throttle	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-2: Containment Spray – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Piping	Pressure Boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.C.EP-63	3.2-1, 022	B A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.C.EP-63	3.2-1, 022	B A

Table 3.2.2-2: Containment Spray – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Pump casing	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Steel components	Pressure boundary	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	V.E.E-28	3.2-1, 009	A
Tank (spray additive)	Pressure boundary	Carbon steel with stainless steel cladding	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Tank (spray additive)	Pressure boundary	Carbon steel with stainless steel cladding	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.C.EP-63	3.2-1, 022	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A

Table 3.2.2-2: Containment Spray – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.C.EP-63	3.2-1, 022	B A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Valve body	Pressure boundary	CASS	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.C.EP-63	3.2-1, 022	B A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.C.EP-63	3.2-1, 022	B A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	V.E.E-02	3.2-1, 014	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	V.E.EP-116	3.2-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	V.E.E-421	3.2-1, 079	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	V.E.E-02	3.2-1, 014	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	V.E.EP-116	3.2-1, 015	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Flow element	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flow element	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Flow element	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Flow element	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Heat exchanger (RHR channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Heat exchanger (RHR channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	C

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (RHR channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (RHR channel head)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	D C
Heat exchanger (RHR shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Heat exchanger (RHR shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-92	3.2-1, 030	B
Heat exchanger (RHR tubes)	Heat transfer	Stainless steel	Treated borated water (int)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-20	3.2-1, 019	B A
Heat exchanger (RHR tubes)	Heat transfer	Stainless steel	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-96	3.2-1, 033	B
Heat exchanger (RHR tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (RHR tubes)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	D C

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (RHR tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-93	3.2-1, 031	B
Heat exchanger (RHR tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.D1.EP-93	3.2-1, 031	E, 1
Heat exchanger (RHR tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (RHR tubesheet)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	D C
Heat exchanger (RHR tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-93	3.2-1, 031	B
Heat exchanger (seal water channel head)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	C
Heat exchanger (seal water shell)	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Heat exchanger (seal water shell)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-92	3.2-1, 030	B

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (seal water shell)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	V.D1.E-43	3.2-1, 035	C
Heat exchanger (seal water tubes)	Heat transfer	Stainless steel	Treated borated water (int)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-20	3.2-1, 019	B A
Heat exchanger (seal water tubes)	Heat transfer	Stainless steel	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-96	3.2-1, 033	B
Heat exchanger (seal water tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (seal water tubes)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	D C
Heat exchanger (seal water tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-93	3.2-1, 031	B
Heat exchanger (seal water tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (seal water tubesheet)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	D C

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (seal water tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-93	3.2-1, 031	B
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Orifice	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Orifice	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Orifice	Throttle	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Orifice	Throttle	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Piping	Pressure boundary	Carbon steel	Hydraulic oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	V.D1.EP-77	3.2-1, 049	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Piping	Pressure boundary	Stainless steel	Concrete (ext)	None	None	V.F.EP-20	3.2-1, 091	A
Piping	Pressure boundary	Stainless steel	Hydraulic oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	V.D1.EP-80	3.2-1, 050	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Piping	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	V.D1.E-13	3.2-1, 001	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Pump casing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Pump casing	Pressure boundary	Carbon steel	Hydraulic oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	V.D1.EP-77	3.2-1, 049	A
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Pump casing	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Pump casing	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	CASS	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Steel components	Pressure boundary	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	V.E.E-28	3.2-1, 009	A
Sump screen	Filter	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Sump screen	Filter	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Tank (hydraulic operator)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Tank (hydraulic operator)	Pressure boundary	Carbon steel	Hydraulic oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	V.D1.EP-77	3.2-1, 049	A
Thermowell	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Thermowell	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Thermowell	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Thermowell	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Valve body	Leakage boundary (spatial)	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Valve body	Leakage boundary (spatial)	CASS	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Valve body	Pressure boundary	Carbon steel	Hydraulic oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	V.D1.EP-77	3.2-1, 049	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Valve body	Pressure boundary	CASS	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.D1.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	Stainless steel	Hydraulic oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	V.D1.EP-80	3.2-1, 050	A
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A

Table 3.2.2-3: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.E-12	3.2-1, 020	B A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 for material, environment, and aging effect but a different AMP is credited.

Plant Specific Notes

1. Eddy current testing is performed on the RHR heat exchanger tubes through the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP based on plant specific OE.

Table 3.2.2-4: Containment Isolation Components – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	V.E.E-02	3.2-1, 014	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	V.E.EP-116	3.2-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	V.E.E-421	3.2-1, 079	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	V.E.E-02	3.2-1, 014	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	V.E.EP-116	3.2-1, 015	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Piping	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.C.EP-103c	3.2-1, 007	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of	V.C.EP-107b	3.2-1, 004	A

Table 3.2.2-4: Containment Isolation Components – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
					Mechanical Components (B.2.3.23)			
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.EP-103d	3.2-1, 007	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.EP-81c	3.2-1, 048	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.C.EP-63	3.2-1, 022	B A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2-1, 040	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.C.EP-103c	3.2-1, 007	A

Table 3.2.2-4: Containment Isolation Components – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.C.EP-107b	3.2-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.EP-103d	3.2-1, 007	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.EP-81c	3.2-1, 048	A
Steel components	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	V.E.E-28	3.2-1, 009	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.C.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.C.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	CASS	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.C.EP-63	3.2-1, 022	B A
Valve body	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A

Table 3.2.2-4: Containment Isolation Components – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.C.EP-103c	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.C.EP-107b	3.2-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.EP-103d	3.2-1, 007	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.EP-81c	3.2-1, 048	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

None

3.3. AGING MANAGEMENT OF AUXILIARY SYSTEMS

3.3.1. Introduction

This section provides the results of the AMR for those components identified in Section 2.3.3, Auxiliary Systems, as being subject to AMR. The systems or portions of systems that are addressed in this section are described in the indicated sections.

- Chemical and Volume Control (2.3.3.1)
- Component Cooling Water (2.3.3.2)
- Spent Fuel Cooling (2.3.3.3)
- Waste Disposal (2.3.3.4)
- Service Water (2.3.3.5)
- Fire Protection (2.3.3.6)
- Heating Steam (2.3.3.7)
- Emergency Power (2.3.3.8)
- Containment Ventilation (2.3.3.9)
- Essential Ventilation (2.3.3.10)
- Treated Water (2.3.3.11)
- Circulating Water (2.3.3.12)
- Containment Hydrogen Detectors (2.3.3.13)
- Primary Sampling (2.3.3.14)
- Plant Air (2.3.3.15)

3.3.2. Results

The following tables summarize the results of the AMR for Auxiliary Systems:

Table 3.3.2-1, Chemical and Volume Control - Summary of Aging Management Evaluation

Table 3.3.2-2, Component Cooling Water - Summary of Aging Management Evaluation

Table 3.3.2-3, Spent Fuel Cooling - Summary of Aging Management Evaluation

Table 3.3.2-4, Waste Disposal - Summary of Aging Management Evaluation

Table 3.3.2-5, Service Water - Summary of Aging Management Evaluation

Table 3.3.2-6, Fire Protection - Summary of Aging Management Evaluation

Table 3.3.2-7, Heating Steam - Summary of Aging Management Evaluation includes heating steam components requiring an AMR for 10 CFR 54.4(a)(2) spatial interactions)

Table 3.3.2-8, Emergency Power – Summary of Aging Management Evaluation

Table 3.3.2-9, Containment Ventilation - Summary of Aging Management Evaluation

Table 3.3.2-10, Essential Ventilation - Summary of Aging Management Evaluation

Table 3.3.2-11, Treated Water - Summary of Aging Management Evaluation (includes treated water components requiring an AMR for 10 CFR 54.4(a)(2) spatial interactions)

Table 3.3.2-12, Circulating Water - Summary of Aging Management Evaluation

Table 3.3.2-13, Containment Hydrogen Detectors - Summary of Aging Management Evaluation

Table 3.3.2-14, Primary Sampling - Summary of Aging Management Evaluation

Table 3.3.2-15, Plant Air - Summary of Aging Management Evaluation

3.3.2.1. Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.3.2.1.1 Chemical and Volume Control

Materials

The materials of construction for the chemical volume and control system components are:

- Carbon steel
- CASS
- Coating
- Glass
- Stainless steel

Environments

The chemical volume and control system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Treated borated water
- Treated borated water >140°F
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the chemical volume and control system require management:

- Cracking
- Cumulative fatigue damage
- Loss of coating or lining integrity
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the chemical volume and control system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- One-Time Inspection (B.2.3.20)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)
- Water Chemistry (B.2.3.2)

3.3.2.1.2 Component Cooling Water

Materials

The materials of construction for the component cooling water system components are:

- Carbon steel
- Coating
- Copper alloy
- Copper alloy >15% Zn
- Gray cast iron
- Stainless steel
- Steel

Environments

The component cooling water system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Lubricating oil
- Raw water
- Treated borated water
- Treated borated water >140°F
- Treated water
- Treated water >140°F

Aging Effects Requiring Management

The following aging effects associated with the component cooling water system require management:

- Cracking
- Flow blockage
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the component cooling water system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Lubricating Oil Analysis (B.2.3.26)
- One-Time Inspection (B.2.3.20)
- Open Cycle Cooling Water System (B.2.3.11)

- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.3.2.1.3 Spent Fuel Cooling

Materials

The materials of construction for the spent fuel cooling system components are:

- Carbon steel
- CASS
- Stainless steel

Environments

The spent fuel cooling system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Raw water
- Treated borated water

Aging Effects Requiring Management

The following aging effects associated with the spent fuel cooling system require management:

- Cracking
- Flow blockage
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the spent fuel cooling system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- One-Time Inspection (B.2.3.20)

- Open-Cycle Cooling Water System (B.2.3.11)
- Water Chemistry (B.2.3.2)

3.3.2.1.4 Waste Disposal

Materials

The materials of construction for the waste disposal system components are:

- Carbon steel
- CASS
- Copper alloy
- Copper alloy >15% Zn
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environments

The waste disposal system components are exposed to the following environments:

- Air - indoor uncontrolled
- Air with borated water leakage
- Treated borated water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the waste disposal system require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning – erosion

Aging Management Programs

The following AMPs manage the aging effects for the waste disposal system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.3.2.1.5 Service Water System

Materials

The materials of construction for the service water system components are:

- Carbon steel
- CASS
- Coating
- Copper alloy
- Copper alloy >15% Zn
- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environments

The service water system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Raw water
- Soil
- Treated borated water

Aging Effects Requiring Management

The following aging effects associated with the service water system require management:

- Cracking
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the service water system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Buried and Underground Piping and Tanks (B.2.3.27)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Fire Water System (B.2.3.16)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- One-Time Inspection (B.2.3.20)
- Open-Cycle Cooling Water System (B.2.3.11)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.3.2.1.6 Fire Protection

Materials

The materials of construction for the fire protection system components are:

- Carbon steel
- CASS
- Coating (cementitious)
- Copper alloy
- Copper alloy >15% Zn

- Glass
- Gray cast iron
- Neoprene
- Stainless steel
- Steel

Environments

The fire protection system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Diesel exhaust
- Fuel oil
- Gas
- Lubricating oil
- Raw water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the fire protection system require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Wall thinning – erosion

Aging Management Programs

The following AMPs manage the aging effects for the fire protection system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)

- Buried and Underground Piping and Tanks (B.2.3.27)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Fire Protection (B.2.3.15)
- Fire Water System (B.2.3.16)
- Fuel Oil Chemistry (B.2.3.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Lubricating Oil Analysis (B.2.3.26)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)

3.3.2.1.7 Heating Steam

Materials

The materials of construction for the heating steam system components are:

- Carbon steel
- Copper alloy
- Copper alloy >15% Zn
- Gray cast iron
- Stainless steel
- Steel

Environments

The heating steam system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the heating steam system require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload

- Wall thinning – erosion
- Wall thinning – FAC

Aging Management Programs

The following AMPs manage the aging effects for the heating steam system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.8)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.3.2.1.8 Emergency Power

Materials

The materials of construction for the emergency power system components are:

- Aluminum
- Carbon steel
- CASS
- Coating
- Copper alloy
- Copper alloy >15% Zn
- Elastomer
- Glass
- Gray cast iron
- Plastic
- Stainless steel

Environments

The emergency power system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Diesel exhaust

- Fuel oil
- Lubricating oil
- Raw water
- Soil
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the emergency power system require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning – erosion

Aging Management Programs

The following AMPs manage the aging effects for the emergency power system components:

- Bolting Integrity (B.2.3.9)
- Buried and Underground Piping and Tanks (B.2.3.27)
- Closed Treated Water Systems (B.2.3.12)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Fuel Oil Chemistry (B.2.3.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Lubricating Oil Analysis (B.2.3.26)
- One-Time Inspection (B.2.3.20)
- Open-Cycle Cooling Water System (B.2.3.11)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)
- Selective Leaching (B.2.3.21)

3.3.2.1.9 Containment Ventilation

Materials

The materials of construction for the containment ventilation system components are:

- Carbon steel
- Copper alloy
- Copper alloy >15% Zn
- Elastomer
- Stainless steel

Environments

The containment ventilation system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Condensation
- Raw water

Aging Effects Requiring Management

The following aging effects associated with the containment ventilation system require management:

- Cracking
- Flow blockage
- Hardening or loss of strength
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the containment ventilation system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)

- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- Open-Cycle Cooling Water System (B.2.3.11)

3.3.2.1.10 Essential Ventilation

Materials

The materials of construction for the essential ventilation system components are:

- Aluminum
- Carbon steel
- Copper alloy
- Elastomer
- Glass
- PVC
- Stainless steel

Environments

The essential ventilation system components are exposed to the following environments:

- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Condensation
- Raw water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the essential ventilation system require management:

- Cracking
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the essential ventilation system components:

- Bolting Integrity (B.2.3.9)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Open-Cycle Cooling Water System (B.2.3.11)

3.3.2.1.11 Treated Water

Materials

The materials of construction for the treated water system components are:

- Carbon steel
- CASS
- Copper alloy
- Stainless steel

Environments

The treated water system components are exposed to the following environments:

- Air - indoor uncontrolled
- Air with borated water leakage
- Raw water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the treated water system require management:

- Cracking
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the treated water system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- One-Time Inspection (B.2.3.20)

3.3.2.1.12 Circulating Water

Materials

The materials of construction for the circulating water system components are:

- Carbon steel
- Gray cast iron
- Stainless steel

Environments

The circulating water system components are exposed to the following environments:

- Air – indoor uncontrolled
- Raw water

Aging Effects Requiring Management

The following aging effects associated with the circulating water system require management:

- Cracking
- Loss of material
- Loss of preload
- Wall thinning – erosion

Aging Management Programs

The following AMPs manage the aging effects for the circulating water system components:

- Bolting Integrity (B.2.3.9)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)

- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- Selective Leaching (B.2.3.21)

3.3.2.1.13 Containment Hydrogen Detectors and Recombiner

Materials

The materials of construction for the containment hydrogen detectors and recombiner system components are:

- Carbon steel
- CASS
- Stainless steel

Environments

The containment hydrogen detectors and recombiner system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects associated with the containment hydrogen detectors and recombiner system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the containment hydrogen detectors and recombiner system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)

3.3.2.1.14 Plant Sampling

Materials

The materials of construction for the plant sampling system components are:

- Carbon steel
- Glass
- Stainless steel

Environments

The plant sampling system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated borated water
- Treated borated water >140°F
- Treated water
- Treated water >140°F

Aging Effects Requiring Management

The following aging effects associated with the plant sampling system require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the plant sampling system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.3.2.1.15 Plant Air

Materials

The materials of construction for the plant air system components are:

- Aluminum
- Carbon steel
- Copper alloy
- Copper alloy >15% Zn
- Stainless steel

Environments

The plant air system components are exposed to the following environments:

- Air - dry
- Air - indoor uncontrolled
- Air with borated water leakage
- Gas

Aging Effects Requiring Management

The following aging effects associated with the plant air system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the plant air system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)

3.3.2.2. AMR Results for Which Further Evaluation is Recommended by the GALL Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the

Auxiliary Systems, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

Line items 3.3-1, 265 through 3.3-1, 269 were added to Table 3.3-1 based on changes associated with SLR-ISG-MECHANICAL-2020-XX.

3.3.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Cumulative fatigue damage of Auxiliary Systems along with Steam and Power Conversion Systems components, as described in SRP-SLR Item 3.2.2.2.1, is addressed as a TLAA in Section 4.3.3, Metal Fatigue of Non-Class 1 Components. SRP item number 3.3-1, 001 related to structural components is evaluated as a TLAA in Section 4.7, Other Plant-Specific Time-Limited Aging Analyses.

3.3.2.2.2 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

Cracking due to stress corrosion cracking (SCC) and cyclic loading could occur in stainless steel (SS) PWR nonregenerative heat exchanger tubing exposed to treated borated water greater than 60 °C (Celsius) [140 °F (Fahrenheit)] in the chemical and volume control system. The existing AMP for monitoring and control of primary water chemistry in PWRs (GALL-SLR Report AMP XI.M2, "Water Chemistry") manages the aging effects of cracking due to SCC. However, control of water chemistry does not preclude cracking due to SCC and cyclic loading. Therefore, the effectiveness of the water chemistry control program should be verified to ensure that cracking is not occurring. If a search of plant-specific operating experience (OE) does not reveal that cracking has occurred in nonregenerative heat exchanger tubing, this aging effect can be considered to be adequately managed by GALL-SLR Report AMP XI.M2. However, if cracking has occurred in nonregenerative heat exchanger tubing, the GALL-SLR Report recommends that AMP XI.M21A, "Closed Treated Water Systems," be evaluated for inclusion of augmented requirements to conduct temperature and radioactivity monitoring of the shell side water, and where component configuration permits, periodic eddy current testing of tubes.

Based on a review of PBN OE, there is no evidence of cracking of nonregenerative heat exchanger tubes. This confirms the adequacy of the Water Chemistry (B.2.3.3) AMP as described in the above text from GALL-SLR. Consistent with the recommendation of NUREG-2191, the Water Chemistry (B.2.3.3) AMP is used to manage cracking due to SCC and cyclic loading in stainless steel nonregenerative heat exchanger tubing.

3.3.2.2.3 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to SCC could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated, (b) insulated, (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the license renewal application (LRA).

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in GALL-SLR Report AMP XI.M32.

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include *tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.*

Auxiliary Systems contain stainless steel bolting, piping, piping components, heat exchanger components, and tanks exposed to both controlled and uncontrolled indoor air as well as outdoor air. A review of PBN OE confirms halides are potentially present in both the indoor and outdoor environments at PBN and SCC has occurred in air environments in the Auxiliary Systems. Additionally, insulated piping and components located indoors, particularly those in standby or periodically operated systems, could conservatively see an accumulation of contaminants from water intrusion through or beneath insulation. As such, stainless steel components exposed to indoor and outdoor air in Auxiliary Systems are susceptible to cracking due to SCC and require management with an appropriate program.

Consistent with the recommendation of GALL-SLR, cracking of these components will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25), and the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP for components exposed to air internally or externally, respectively. The exception to this is bolting, which is managed by the Bolting Integrity (B.2.3.9) AMP for stainless steel components susceptible to cracking for the Auxiliary Systems. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Bolting Integrity (B.2.3.9), Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25), and External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMPs are described in Sections B.2.3.9, B.2.3.25, and B.2.3.23 respectively.

3.3.2.2.4 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel *alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.*

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in GALL-SLR Report AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope

Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

Auxiliary Systems contain stainless steel bolting, piping, piping components, heat exchanger components, and tanks exposed to both controlled and uncontrolled indoor air. A review of PBN OE confirms halides are potentially present in both the indoor and outdoor environments at PBN, and SCC has occurred in air environments in the Auxiliary Systems. Additionally, insulated piping and components located indoors, particularly those in standby or periodically operated systems, could conservatively see an accumulation of contaminants from water intrusion through or beneath insulation. As such, all stainless steel components exposed to uncontrolled indoor and outdoor air in the Auxiliary Systems are susceptible to loss of material due to pitting and crevice corrosion and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, loss of material in these components will be managed via the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) and the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP for components exposed to air internally or externally, respectively. The exception to this is bolting, which is managed by the Bolting Integrity (B.2.3.9) AMP. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of loss of material will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) AMP is not used to manage loss of material of the base metal. The Bolting Integrity (B.2.3.9), Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) and External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMPs are described in Sections B.2.3.9, B.2.3.25 and B.2.3.23, respectively.

3.3.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in Branch Technical Position (BTP) IQMB-1 (Appendix A.2 of this SRP-SLR.)

Quality Assurance provisions applicable to SLR are discussed in Section B.1.3.

3.3.2.2.6 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs."

The Operating Experience process and acceptance criteria are described in Section B.1.4.

3.3.2.2.7 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant-specific OE conducted during the SLRA development, recurring internal corrosion can be *identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant specific OE reveals repetitive occurrences. The criteria for recurrence is (a) a 10 year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5 year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).*

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M20, "Open-Cycle Cooling Water System," GALL-SLR Report AMP XI.M27, "Fire Water System," or GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10-year search of plant-specific OE, two instances of 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

Site OE over the past 10 years shows some limited recurrence of external corrosion for mechanical components from leakage and an instance of > 50 percent wall loss in heat exchanger tubes. However, there have been no corrosion issues that meet the criteria of recurring internal corrosion. Therefore, recurring internal corrosion is not an applicable aging effect for metals in PBN systems containing raw water, waste water, closed-cycle cooling water, or treated water. As such, credited PBN AMPs such as Fire Water System (B.2.3.16), Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25), and Open-Cycle Cooling Water System (B.2.3.11), do not require augmentation due to recurring internal corrosion.

3.3.2.2.8 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of SLR, acceptance criteria for this further evaluation is being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

Susceptible Material: If the material is not susceptible to SCC then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, *product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.*

<u>Aggressive Environment</u>: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an *acceptable program to manage the integrity of a barrier coating for internal or external coatings.*

Auxiliary Systems contain aluminum piping and piping components exposed to uncontrolled indoor air. A review of PBN OE confirms halides are potentially present in the indoor environment at PBN. As such, all aluminum components exposed to uncontrolled indoor air in the Auxiliary Systems are susceptible to cracking due to SCC and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, cracking of these components will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) and the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMPs for components exposed to air internally or externally, respectively. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) and External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMPs are described in Sections B.2.3.25 and B.2.3.23, respectively.

3.3.2.2.9 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components, loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and *cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.*

The Auxiliary Systems includes both steel and stainless steel piping and tanks exposed to concrete. The concrete at PBN is designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. The stainless steel components are above groundwater and, therefore, do not require management as detailed above. A review of OE for PBN indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface; therefore, a loss of material due to general, pitting, and crevice corrosion of steel piping and tanks exposed to concrete is an aging effect that requires management.

Consistent with the recommendation of GALL-SLR, the Buried and Underground Piping and Tanks (B.2.3.27) and Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMPs are used to manage loss of material in steel piping and tanks exposed to concrete. This AMP provides for the management of aging effects. Any evidence of loss of material will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Buried and Underground Piping and Tanks (B.2.3.27) and Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMPs are described in Sections B.2.3.27 and B.2.3.17, respectively.

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is *occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.*

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in GALL-SLR Report AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

Auxiliary Systems contain aluminum piping and piping components exposed to uncontrolled indoor air. A review of PBN OE confirms halides are potentially present in the indoor environments at PBN. As such, all aluminum components exposed to uncontrolled outdoor air in the Auxiliary Systems are susceptible to loss of material and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, loss of material of these components will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) and the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP for components exposed to air internally or externally, respectively. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of loss of material will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) and External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMPs are described in Sections B.2.3.25 and B.2.3.23, respectively.

3.3.2.3. Time-Limited Aging Analysis

The TLAAs identified below are associated with the Auxiliary Systems components:

- Section 4.3, Metal Fatigue

3.3.3. Conclusion

Auxiliary Systems piping, fittings, and components that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4. The AMPs selected to manage aging effects for Auxiliary Systems components are identified in the summaries in Section 3.3.2 above.

A description of these AMPs is provided in Appendix B along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with Auxiliary Systems components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the CLB during the SPEO.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 001	Steel cranes: bridges, structural members, structural components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.7, "Other Plant-Specific TLAAs"	Yes (SRP-SLR Section 3.3.2.2.1)	Consistent with NUREG-2191. The Other Plant-Specific TLAAs are used to manage cumulative fatigue damage in steel cranes, bridges, structural members, and structural components exposed to any environment. This line item is used to evaluate structural items in Section 3.5. Further evaluation is documented in Section 3.3.2.2.1.
3.3-1, 002	Stainless steel, steel heat exchanger components and tubes, piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3, "Metal Fatigue"	Yes (SRP-SLR Section 3.3.2.2.1)	Consistent with NUREG-2191. The Metal Fatigue of Non-Class 1 Components TLAA is used to manage cumulative fatigue damage in steel and stainless steel piping, and piping components exposed to any environment. Further evaluation is documented in Section 3.3.2.2.1.
3.3-1, 003	Stainless steel heat exchanger tubing, non-regenerative exposed to treated borated water >60°C (>140°F)	Cracking due to SCC; cyclic loading	AMP XI.M2, "Water Chemistry"	Yes (SRP-SLR Section 3.3.2.2.2)	Consistent with NUREG-2191 with exception. The Water Chemistry (B.2.3.2) AMP is used to manage cracking of stainless steel non-regenerative heat exchanger tubes exposed to treated borated water >140°F. Further evaluation is documented in Section 3.3.2.2.2.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 003a	Stainless steel heat exchanger tubing, non-regenerative exposed to treated borated water >60°C (>140°F)	Cracking due to SCC; cyclic loading	AMP XI.M2, "Water Chemistry," and AMP XI.M21A, "Closed Treated Water Systems"	Yes (SRP-SLR Section 3.3.2.2.2)	Not used. Management of cracking in stainless steel heat exchanger tubing is addressed using a different line item (3.3-1, 020).
3.3-1, 004	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191. This line item is also applied to heat exchanger shells. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMPs are used to manage cracking of stainless steel piping, piping components, heat exchanger shells, and tanks exposed to air externally and internally. Further evaluation is documented in Section 3.3.2.2.3.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 006	Stainless steel, nickel alloy piping, piping components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191 for piping, piping components, and tanks. This line item is also applied to heat exchanger shells. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMPs are used to manage external and internal loss of material of stainless steel piping, piping components, heat exchanger shells, and tanks exposed to air externally and internally. Further evaluation is documented in Section 3.3.2.2.4.
3.3-1, 007	Stainless steel high- pressure pump, casing exposed to treated borated water	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Sections IWB, IWC, and IWD"	No	Not applicable. There are no stainless steel high-pressure pumps subject to cyclic loading associated with the Auxiliary Systems.
3.3-1, 008	Stainless steel heat exchanger components and tubes exposed to treated borated water >60°C (>140°F)	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Sections IWB, IWC, and IWD"	No	Not used. Management of cracking in stainless steel heat exchanger tubing is addressed using a different line item (3.3-1, 020).
3.3-1, 009	Steel, copper alloy (>15% Zn) external surfaces, piping, piping components exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Consistent with NUREG-2191. The Boric Acid Corrosion (B.2.3.4) AMP is used to manage loss of material of steel and copper alloy >15% Zn components exposed to air with borated water leakage.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 010	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, "Bolting Integrity"	No	Not applicable. There is no high-strength bolting associated with the Auxiliary Systems.
3.3-1, 012	Steel; stainless steel, nickel alloy closure bolting exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage loss of material in steel and stainless steel closure bolting exposed to outdoor air or uncontrolled indoor air.
3.3-1, 015	Metallic closure bolting exposed to any environment, soil, underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage loss of preload in metallic closure bolting exposed to any environment.
3.3-1, 016	This line item only applies to BWRs.				
3.3-1, 017	Stainless steel heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage reduction of heat transfer in stainless steel heat exchanger tubes exposed to treated borated water.
3.3-1, 018	Stainless steel high- pressure pump casing, piping, piping components, tanks exposed to treated borated water >60°C (>140°F), sodium pentaborate solution >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not used. Management of cracking in stainless steel piping and piping components is addressed using a different line item (3.3-1, 124).
3.3-1, 019	This line item only applies to BWRs.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 020	Stainless steel, steel with stainless steel cladding heat exchanger components exposed to treated borated water >60°C (>140°F), treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage cracking of stainless steel heat exchanger components exposed to treated borated water >60°C (>140°F)
3.3-1, 021	This line item only applies to BWRs.				
3.3-1, 022	This line item only applies to BWRs.				
3.3-1, 025	Aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There is no aluminum piping exposed to treated water or treated borated water in the Auxiliary Systems.
3.3-1, 026	This line item only applies to BWRs.				
3.3-1, 027	This line item only applies to BWRs.				
3.3-1, 028	Stainless steel piping, piping components, tanks exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage cracking of stainless steel piping and piping components exposed to treated borated water >60°C (>140°F) in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 030	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no concrete components exposed to raw water within the scope of the Open-Cycle Cooling Water System (B.2.3.11) AMP.
3.3-1, 030a	Fiberglass, HDPE piping, piping components exposed to raw water	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no fiberglass piping or piping components exposed to raw water.
3.3-1, 034	Nickel alloy, copper alloy piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191 with exception. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage loss of material and flow blockage in copper alloy and copper alloy piping and piping components exposed to raw water.
3.3-1, 037	Steel piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191 with exception. This line item is also used for heat exchanger components. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage loss of material and flow blockage in steel piping, piping components, and heat exchanger components exposed to raw water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 038	Copper alloy, steel heat exchanger components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191 with exception. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage loss of material and flow blockage in copper alloy and steel heat exchanger components exposed to raw water.
3.3-1, 040	Stainless steel piping, piping components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191 with exception. This line item has also been applied to heat exchanger components. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage loss of material and flow blockage in stainless steel piping, piping components, and heat exchanger components exposed to raw water.
3.3-1, 042	Copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water, raw water (potable), treated water	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191 with exception for the Open-Cycle Cooling Water System (B.2.3.11) AMP. The Open-Cycle Cooling Water System (B.2.3.11) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMPs are both used to manage reduction of heat transfer in stainless steel and copper heat exchanger tubes exposed to raw and treated water.
3.3-1, 043	Stainless steel piping, piping components exposed to closed- cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no stainless steel piping or piping components exposed to closed-cycle cooling water >60°C (>140°F) in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 044	Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no steel or stainless steel heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F) in the Auxiliary Systems.
3.3-1, 045	Steel piping, piping components, tanks exposed to closed- cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. This line item has also been applied to heat exchanger components. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage the loss of material of steel piping, piping components, tanks, and heat exchanger components when exposed to closed-cycle cooling water in the Auxiliary Systems.
3.3-1, 046	Steel, copper alloy heat exchanger components, piping, piping components exposed to closed- cycle cooling water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage loss of material in steel and copper alloy heat exchanger components, piping, and piping components exposed to closed-cycle cooling water in the Auxiliary Systems.
3.3-1, 047	This line item only applies to BWRs.				
3.3-1, 048	Aluminum piping, piping components exposed to closed- cycle cooling water	Loss of material due to pitting, crevice corrosion	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no aluminum piping or piping components exposed to closed-cycle cooling water in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 049	Stainless steel piping, piping components exposed to closed- cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. This line item has also been applied to heat exchanger components, including heat exchanger components in the reactor coolant and connected piping system. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage the loss of material of stainless steel piping, piping components, and heat exchanger components when exposed to closed-cycle cooling water in the Auxiliary Systems.
3.3-1, 050	Stainless steel, copper alloy, steel heat exchanger tubes exposed to closed- cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exception. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage reduction of heat transfer for stainless steel and copper heat exchanger tubes exposed to closed-cycle cooling water >60°C (>140°F).
3.3-1, 051	Boraflex spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water	Reduction of neutron- absorbing capacity due to boraflex degradation	AMP XI.M22, "Boraflex Monitoring"	No	Not applicable. There are no boraflex components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 052	Steel cranes: rails, bridges, structural members, structural components exposed to air	Loss of material due to general corrosion, wear, deformation, cracking	AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems"	No	Consistent with NUREG-2191. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13) AMP is used to manage steel cranes: rails, bridges, structural members, or structural components exposed to air. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 055	Steel piping, piping components, tanks exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel piping, piping components, tanks exposed to condensation in the Auxiliary Systems.
3.3-1, 057	Elastomer fire barrier penetration seals exposed to air, condensation	Hardening, loss of strength, shrinkage due to elastomer degradation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. This line item is used for components exposed to uncontrolled indoor air. The Fire Protection (B.2.3.15) AMP is used to manage hardening, loss of strength, and shrinkage of elastomer fire barriers exposed to uncontrolled indoor air. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 058	Steel halon/carbon dioxide fire suppression system piping, piping components exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191 for steel piping and piping components. The Fire Protection (B.2.3.15) AMP is used to manage loss of material of steel fire suppression system piping and piping components, exposed to uncontrolled air.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 059	Steel fire rated doors exposed to air	Loss of material due to wear	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.3.15) AMP is used to manage loss of material of steel fire rated doors exposed to air. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 060	Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M26, "Fire Protection," and AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Fire Protection (B.2.3.15) and Structures Monitoring (B.2.3.34) AMPs are used to manage cracking and loss of material of reinforced concrete structural fire barriers. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 063	Steel fire hydrants exposed to air – outdoor, raw water, raw water (potable), treated water	Loss of material due to general, pitting, crevice corrosion; flow blockage due to fouling (raw water, raw water (potable) only)	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191. This line is used for gray cast iron components. The Fire Water System (B.2.3.16) AMP is used to manage loss of material and flow blockage of gray cast iron fire hydrants exposed to air or raw water.
3.3-1, 064	Steel, copper alloy piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to general (steel; copper alloy in raw water and raw water (potable) only), pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water; raw water (potable) for steel only)	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191. The Fire Water System (B.2.3.16) AMP is used to manage loss of material and flow blockage of steel and copper alloy piping and piping components exposed to raw water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 065	Aluminum piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to pitting, crevice corrosion; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no aluminum piping or piping components exposed to raw water or treated water in the Auxiliary Systems.
3.3-1, 066	Stainless steel piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191. The Fire Water System (B.2.3.16) AMP is used to manage loss of material and flow blockage of stainless steel piping and piping components exposed to raw water or treated water.
3.3-1, 069	Copper alloy piping, piping components exposed to fuel oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M30, "Fuel Oil Chemistry," and AMP XI.M32, "One-Time Inspection," or AMP XI.M30, "Fuel Oil Chemistry"	No	Consistent with NUREG-2191 with exception for the Fuel Oil Chemistry (B.2.3.18) AMP. The Fuel Oil Chemistry (B.2.3.18) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material in copper alloy piping and piping components exposed to fuel oil.
3.3-1, 070	Steel piping, piping components, tanks exposed to fuel oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M30, "Fuel Oil Chemistry," and AMP XI.M32, "One-Time Inspection," or AMP XI.M30, "Fuel Oil Chemistry"	No	Consistent with NUREG-2191 with exception with the Fuel Oil Chemistry (B.2.3.18) AMP. The Fuel Oil Chemistry (B.2.3.18) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material in steel piping, piping components, and tanks exposed to fuel oil.
3.3-1, 071	Stainless steel, aluminum piping, piping components exposed to fuel oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M30, "Fuel Oil Chemistry," and AMP XI.M32, "One-Time Inspection," or AMP XI.M30, "Fuel Oil Chemistry"	No	Consistent with NUREG-2191 with exception with the Fuel Oil Chemistry (B.2.3.18) AMP. The Fuel Oil Chemistry (B.2.3.18) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material in stainless steel piping and piping components exposed to fuel oil.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 072	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to treated water, closed-cycle cooling water, soil, raw water, raw water (potable), waste water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Consistent with NUREG-2191. The Selective Leaching (B.2.3.21) AMP is used to manage loss of material of gray cast iron, and copper alloy >15% Zn piping, piping components, and heat exchanger components exposed to raw water, treated water, waste water, and soil.
3.3-1, 073	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to air – outdoor	Cracking due to chemical reaction, weathering, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no concrete or cementitious piping or piping components exposed to outdoor air in the Auxiliary Systems.
3.3-1, 076	Elastomer piping, piping components, ducting, ducting components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage hardening or loss of strength of elastomer ducting, ducting components, and seals exposed to air.
3.3-1, 078	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material for steel external surfaces exposed to outdoor and uncontrolled air.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 080	Steel heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material for steel heat exchanger components, piping, and piping components exposed to uncontrolled air.
3.3-1, 082	Elastomer, fiberglass piping, piping components, ducting, ducting components, seals exposed to air	Loss of material due to wear	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material for elastomer piping components, ducting, ducting components, and seals exposed to air.
3.3-1, 083	Stainless steel diesel engine exhaust piping, piping components exposed to diesel exhaust	Cracking due to SCC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage cracking of stainless steel piping and piping components exposed to diesel engine exhaust.
3.3-1, 085	Elastomer piping, piping components, seals exposed to air, condensation, closed- cycle cooling water, treated borated water, treated water, raw water, raw water (potable), waste water, gas, fuel oil, lubricating oil	Hardening or loss of strength due to elastomer degradation; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. This line item is also applied to elastomer ducting. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage hardening or loss of strength and flow blockage for elastomer piping, piping components, and ducting when exposed to indoor uncontrolled air or raw water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 088	Steel; stainless steel piping, piping components, diesel engine exhaust exposed to raw water (potable), diesel exhaust	Loss of material due to general (steel only), pitting, crevice corrosion, flow blockage due to fouling (steel only for raw water (potable) environment)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. This items is also used for heat exchanger components. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) is used to manage loss of material and flow blockage for steel components exposed to raw water and diesel exhaust.
3.3-1, 089	Steel piping, piping components exposed to condensation (internal)	Loss of material due to general, pitting, crevice corrosion	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no steel piping or piping components exposed to internal condensation that are associated with fire suppression and managed under the Fire Water System (B.2.3.16) AMP.
3.3-1, 090	Steel ducting, ducting components (internal surfaces) exposed to condensation	Loss of material due to general, pitting, crevice corrosion, MIC (for drip pans and drain lines only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel ducting, ducting components (internal surfaces) exposed to condensation that are associated with the Auxiliary Systems.
3.3-1, 091	Steel piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) is used to manage loss of material and flow blockage of steel piping and piping components exposed to waste water.
3.3-1, 093	Copper alloy piping, piping components exposed to raw water (potable)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage loss of material in copper piping and piping components exposed to raw water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 094	Stainless steel ducting, ducting components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.3.2.2.4)	Not applicable. There are no stainless steel ducting, ducting components exposed to air, condensation that are associated with the Auxiliary System.
3.3-1, 094a	Stainless steel ducting, ducting components exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.3.2.2.3)	Not applicable. There are no stainless steel ducting, ducting components exposed to air, condensation that are associated with the Auxiliary System.
3.3-1, 095	Copper alloy, stainless steel, nickel alloy piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage loss of material and flow blockage in copper, steel, and stainless steel piping and piping components exposed to waste water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 096	Elastomer piping, piping components, seals exposed to air, raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage loss of material and flow blockage of elastomer expansion joints exposed to raw water or air.
3.3-1, 096a	Steel, aluminum, copper alloy, stainless steel, titanium heat exchanger tubes internal to components exposed to air, condensation (external)	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage reduction of heat transfer in copper alloy or copper alloy heat exchanger tubes exposed to air.
3.3-1, 096b	Steel heat exchanger components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no steel heat exchanger components exposed to condensation within the Auxiliary Systems.
3.3-1, 097	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.26) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material in steel components exposed to lubricating oil.
3.3-1, 098	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.26) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel heat exchanger components exposed to lubricating oil.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 099	Copper alloy, aluminum piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC (copper alloy only)	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.26) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of copper alloy components exposed to lubricating oil.
3.3-1, 100	Stainless steel piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.26) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel components exposed to lubricating oil.
3.3-1, 101	Aluminum heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no aluminum piping, piping components exposed to lubricating oil in the Auxiliary Systems.
3.3-1, 102	Boral®; boron steel, and other materials (excluding Boraflex) spent fuel storage racks: neutron- absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water	Reduction of neutron- absorbing capacity; change in dimensions and loss of material due to effects of SFP environment	AMP XI.M40, "Monitoring of Neutron-Absorbing Materials other than Boraflex"	No	Not applicable. There are no neutron absorbing materials components exposed to treated borated water or treated water in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 103	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to soil, concrete	Cracking due to chemical reaction, weathering, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, or piping components exposed to soil or concrete in the Auxiliary Systems.
3.3-1, 104	High-density polyethylene (HDPE), fiberglass piping, piping components exposed to soil, concrete	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no HDPE or fiberglass piping or piping components in the Auxiliary Systems.
3.3-1, 107	Stainless steel, nickel alloy piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are stainless steel or nickel alloy piping, or piping components exposed to concrete in the Auxiliary Systems. However, the stainless steel components are above groundwater and therefore, do not require aging management.
3.3-1, 108	Titanium, super austenitic, copper alloy, stainless steel, nickel alloy piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC (super austenitic, copper alloy, stainless steel, nickel alloy; soil environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191 with exception. The Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage loss of material in stainless steel closure bolting exposed to soil.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 109	Steel piping, piping components, closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191 with exception. The Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage loss of material in steel piping, piping components, and closure bolting exposed to soil or concrete.
3.3-1, 110	This line item only applies to BWRs.				
3.3-1, 111	Steel structural steel exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structure Monitoring AMP is used to manage loss of material in structural steel exposed to uncontrolled indoor air. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 112	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.3.2.2.9)	Not used. A review of OE for PBN indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface; therefore, a loss of material due to general, pitting, and crevice corrosion of steel piping exposed to concrete is an aging effect that requires management. (Line item 3.3-1, 109.)
3.3-1, 113	Aluminum piping, piping components exposed to gas	None	None	No	Not applicable. There are no aluminum piping and piping components exposed to gas in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 114	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191. This line item is also applied to heat exchanger components. There are no aging effects that require management for copper piping, piping components, and heat exchanger components exposed to gas or air that would affect the pressure boundary intended function.
3.3-1, 115	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. There are no copper alloy or copper alloy >8% Al piping or piping components exposed to air with borated water leakage in the Auxiliary Systems.
3.3-1, 116	Galvanized steel piping, piping components exposed to air – indoor uncontrolled	None	None	No	Not applicable. There are no galvanized steel piping and piping components exposed to indoor uncontrolled air in the Auxiliary Systems.
3.3-1, 117	Glass piping elements exposed to air, lubricating oil, closed- cycle cooling water, fuel oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, underground	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for glass piping elements.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 119	Nickel alloy, PVC, glass piping, piping components exposed to air with borated water leakage, air – indoor uncontrolled, condensation, waste water, raw water (potable)	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for plastic exposed to air or condensation or glass components exposed to waste water in the Auxiliary Systems.
3.3-1, 120	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for stainless steel piping and piping components exposed to air with borated water leakage or gas.
3.3-1, 121	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191. This line item is also applied to steel accumulators exposed to gas. There are no aging effects that require management for steel piping, piping components, tanks, and structural items exposed to gas or indoor controlled air.
3.3-1, 122	Titanium heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	None	None	No	Not applicable. There are no titanium components in the Auxiliary Systems.
3.3-1, 123	Titanium heat exchanger components other than tubes, piping and piping components exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no titanium components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 124	Stainless steel, steel (with stainless steel or nickel alloy cladding) spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components exposed to treated water >60°C (>140°F), treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage cracking of stainless steel piping and piping components exposed to treated borated water >60°C (>140°F) in the Auxiliary Systems.
3.3-1, 125	Stainless steel, steel (with stainless steel cladding), nickel alloy spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. This line item is also applied to stainless steel heat exchanger components, tanks, spent fuel storage and transfer components, and reactor cavity seal rings. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel components exposed to treated borated water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 126	Metallic piping, piping components exposed to treated water, treated borated water, raw water	Wall thinning due to erosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191 with exception for the Open-Cycle Cooling Water System (B.2.3.11) AMP. The Fire Water System (B.2.3.16), Open-Cycle Cooling Water System (B.2.3.11), and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMPs are credited with managing wall thinning due to erosion of metallic components exposed to raw and waste water. Erosion is not an applicable aging effect in treated water or treated borated water environments in the Auxiliary Systems.
3.3-1, 127	Metallic piping, piping components, tanks exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M27, "Fire Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.3.2.2.7)	Not applicable. OE shows no instances that meet the criteria of recurring internal corrosion.
3.3-1, 128	Steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation, raw water	Loss of material due to general, pitting, crevice corrosion, MIC (soil, raw water only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material in steel tanks exposed to uncontrolled air or concrete.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 130	Metallic sprinklers exposed to air, condensation, raw water, raw water (potable), treated water	Loss of material due to general (where applicable), pitting, crevice corrosion, MIC (except for aluminum, and in raw water, raw water (potable), treated water only); flow blockage due to fouling	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191. The Fire Water System (B.2.3.16) AMP is used to manage loss of material and flow blockage in metallic sprinklers exposed to air or raw water.
3.3-1, 131	Steel, stainless steel, copper alloy, aluminum piping, piping components exposed to air, condensation	Flow blockage due to fouling	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191. The Fire Water System (B.2.3.16) AMP is used to manage flow blockage in copper alloy sprinklers exposed to uncontrolled air.
3.3-1, 132	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. This line item is also applied to insulated heat exchanger shells and channel heads. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material of steel insulated piping, piping components, and heat exchanger shells and channel heads along with cracking of copper alloy components exposed to uncontrolled air.
3.3-1, 133	HDPE underground piping, piping components	Cracking, blistering	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no HDPE underground piping or piping components included in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 134	Steel, stainless steel, copper alloy piping, piping components, and heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage loss of material in steel and stainless steel piping, piping components, and heat exchanger exposed to raw water internally.
3.3-1, 135	Steel, stainless steel pump casings exposed to waste water environment	Loss of material due to general (steel only), pitting, crevice corrosion, MIC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no steel or stainless steel pump casings externally exposed to waste water in the Auxiliary Systems.
3.3-1, 136	Steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to general, pitting, crevice corrosion, MIC (raw water, raw water (potable), treated water, soil only)	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191 for steel fire water storage tanks. This line item is also applied to gray cast iron compressor casings. The Fire Water System (B.2.3.16) AMP is used to manage loss of material in steel fire water storage tanks and gray cast iron compressor casings exposed to uncontrolled air and raw water.
3.3-1, 137	Steel, stainless steel, aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water, raw water, waste water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material in steel tanks that are exposed to treated water, in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 138	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed- cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191 with exception. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) AMP is used to manage loss of coating or lining integrity for any material with a coating for cementitious coatings/linings.
3.3-1, 139	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed- cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not used. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) AMP is not used to manage loss of material.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 140	Gray cast iron, ductile iron piping components with internal coatings/linings exposed to closed- cycle cooling water, raw water, raw water (potable), treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not used. Any gray cast iron components with internal coatings have the coatings managed via Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) AMP while the selective leaching of the base metal is addressed under the appropriate Selective Leaching (B.2.3.21) AMP line item.
3.3-1, 142	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to fuel oil, lubricating oil, treated water, treated borated water, raw water, waste water	Loss of material due to general (steel; copper alloy in raw water, waste water only), pitting, crevice corrosion, MIC (raw water and waste water environments only)	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage loss of material of steel and stainless steel closure bolts exposed to raw water.
3.3-1, 144	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191 with exception. The Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage cracking for steel tanks exposed to soil.
3.3-1, 145	Stainless steel closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage cracking of stainless steel closure bolting.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 146	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Not applicable. There are no stainless steel underground piping, piping components, or tanks in the Auxiliary Systems.
3.3-1, 147	Nickel alloy, nickel alloy cladding piping, piping components exposed to closed- cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no nickel alloy or nickel alloy clad piping or piping components exposed to closed-cycle cooling water in the Auxiliary Systems.
3.3-1, 149	Fiberglass piping, piping components, ducting, ducting components exposed to air – outdoor	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no fiberglass components in the Auxiliary Systems that require aging management.
3.3-1, 150	Fiberglass piping, piping components, ducting, ducting components exposed to air	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no fiberglass components in the Auxiliary Systems that require aging management.
3.3-1, 151	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage reduction in heat transfer in copper alloy heat exchanger components exposed to a condensation environment.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 155	Stainless steel piping, piping components, and tanks exposed to waste water >60°C (>140°F)	Cracking due to SCC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. The Auxiliary Systems does not include any waste water >60°C (>140°F).
3.3-1, 157	Steel piping, piping components, heat exchanger components exposed to air-outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M27, "Fire Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not used. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material in steel components exposed to outdoor air externally per item 3.3-1, 078.
3.3-1, 158	Nickel alloy piping, piping components heat exchanger components (for components not covered by NRC GL 89-13) exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no nickel alloy piping, piping components, or heat exchanger components exposed to raw water in the Auxiliary Systems.
3.3-1, 159	Fiberglass piping, piping components, ducting, ducting components exposed to air	Loss of material due to wear	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no fiberglass components in the Auxiliary Systems that require aging management.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 160	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, raw water, waste water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M21A, "Closed Treated Water Systems," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191 with exception for Open-Cycle Cooling Water System (B.2.3.11) and Closed Treated Water Systems (B.2.3.12) AMPs. The Open-Cycle Cooling Water System (B.2.3.11), Closed Treated Water Systems (B.2.3.12), and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage cracking in copper alloy components exposed to a waste water environment. Additionally, the Fire Water System (B.2.3.16) AMP is used to manage cracking in copper alloy components exposed to a raw water environment.
3.3-1, 161	Copper alloy heat exchanger tubes exposed to condensation	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not used. The aging management of copper alloy heat exchanger components exposed to condensation is included under line item 3.3-1, 151.
3.3-1, 166	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. There are no copper alloy components exposed to concrete in the Auxiliary Systems.
3.3-1, 167	Zinc piping components exposed to air-indoor controlled, air – indoor uncontrolled	None	None	No	Not applicable. There are no zinc components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 169	Steel, copper alloy piping, piping components exposed to steam	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material in copper alloy components exposed to a steam environment. Steel piping and piping components are addressed in line item 3.4-1, 014.
3.3-1, 170	Stainless steel piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no stainless steel piping and piping components exposed to steam in the Auxiliary Systems that require aging management.
3.3-1, 172	PVC piping, piping components exposed to air-outdoor	Reduction in impact strength due to photolysis	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no PVC piping or piping components in the Auxiliary Systems exposed to outdoor air
3.3-1, 175	Fiberglass piping, piping components, tanks exposed to raw water (for components not covered by NRC GL 89-13), raw water (potable), treated water, waste water	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no fiberglass piping, piping components, or tanks in the Auxiliary Systems that require aging management.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 176	Fiberglass piping, piping components, tanks exposed to raw water environment (for components not covered by NRC GL 89-13), raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no fiberglass piping, piping components, or tanks in the Auxiliary Systems that require aging management.
3.3-1, 177	Fiberglass piping, piping components exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no fiberglass piping or piping components in the Auxiliary Systems that require aging management.
3.3-1, 178	Fiberglass piping and piping components exposed to concrete	None	None	No	Not applicable. There are no fiberglass piping or piping components in the Auxiliary Systems that require aging management.
3.3-1, 179	Masonry walls: structural fire barriers exposed to air	Cracking due to restraint shrinkage, creep, aggressive environment; loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.M26, "Fire Protection," and AMP XI.S5, "Masonry Walls"	No	Consistent with NUREG-2191. The Fire Protection (B.2.3.15) and Masonry Walls (B.2.3.33) AMPs are used to manage cracking and loss of material for masonry walls and structural fire barriers exposed to air and soil. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 181	Titanium piping, piping components exposed to condensation	None	None	No	Not applicable. There are no titanium piping or piping components in the Auxiliary Systems.
3.3-1, 182	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no thermal insulation in the Auxiliary Systems that require aging management.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 184	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. There are no PVC piping, piping components, or tanks in the Auxiliary Systems exposed to concrete.
3.3-1, 185	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Cracking due to SCC	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no aluminum fire water storage tanks in the Auxiliary Systems.
3.3-1, 186	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no large or outdoor aluminum tanks in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 189	Aluminum piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), waste water	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMPs are used to manage cracking of aluminum components exposed to indoor uncontrolled air. Further evaluation is documented in Section 3.3.2.2.8.
3.3-1, 192	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no aluminum underground piping, piping components, or tanks in the Auxiliary Systems.
3.3-1, 193	Steel components exposed to treated water, raw water, raw water (potable), waste water	Long-term loss of material due to general corrosion	AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage long-term loss of material in steel components exposed to raw water or waste water. Long-term loss of material is not applicable for treated water systems material because corrosion inhibitors are used.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 194	PVC piping, piping components, and tanks exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no PVC piping or piping components in the Auxiliary Systems exposed to soil that require aging management.
3.3-1, 195	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no concrete or cementitious piping or piping components associated with fire protection that require aging management.
3.3-1, 196	HDPE piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking, blistering; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no HDPE piping or piping components that require aging management.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 197	Metallic fire water system piping, piping components, heat exchanger, heat exchanger components (any material) with only a leakage boundary (spatial) or structural integrity (attached) intended function exposed to any external environment except soil, concrete	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material in metallic piping, and piping components exposed to an indoor uncontrolled air environment.
3.3-1, 198	Metallic fire water system piping, piping components, heat exchanger, heat exchanger components (any material) with only a leakage boundary (spatial) or structural integrity (attached) intended function	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC (all metallic materials except aluminum; in liquid environments only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage loss of material in metallic piping, and piping components exposed to a treated water environment.
3.3-1, 199	Cranes: steel structural bolting exposed to air	Loss of preload due to self-loosening; loss of material due to general corrosion; cracking	AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems"	No	Consistent with NUREG-2191. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13) AMP is used to manage loss of preload, loss of material, and cracking for steel components exposed to uncontrolled air. This line item is used to evaluate structural items in Section 3.5.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 202	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.3.2.2.9)	Not applicable. There are no stainless steel piping or piping components exposed to concrete in the auxiliary systems.
3.3-1, 203	This line item only applies to BWRs.				
3.3-1, 205	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191. This item is also used for insulated heat exchanger shells and channel heads. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage cracking of insulated stainless steel piping, piping components, and heat exchanger shells and channel heads exposed to air. Further evaluation is documented in Section 3.3.2.2.3.
3.3-1, 207	Stainless steel, copper alloy, titanium heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not used. Stainless steel and copper alloy heat exchanger tubes exposed to raw water are managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP via line item 3.3-1, 042.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 208	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no concrete or cementitious piping or piping components exposed to raw water that requires aging management.
3.3-1, 210	HDPE piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Cracking, blistering; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no HDPE piping or piping components in the Auxiliary Systems that require aging management.
3.3-1, 214	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no copper alloy piping or piping components exposed to soil in the Auxiliary Systems.
3.3-1, 215	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no aluminum fire water storage tanks in the Auxiliary Systems.
3.3-1, 216	Stainless steel fire water storage tanks exposed to air, condensation, soil, concrete	Cracking due to SCC	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no stainless steel fire water storage tanks in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 218	Stainless steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion, MIC (water and soil environment only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no stainless steel fire water storage tanks in the Auxiliary Systems.
3.3-1, 219	Stainless steel piping, piping components exposed to steam	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no stainless steel piping and piping components exposed to steam in the Auxiliary Systems that require aging management.
3.3-1, 222	Stainless steel, nickel alloy tanks exposed to air, condensation (internal/external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material in stainless steel tanks exposed to uncontrolled air externally. Further evaluation is documented in Section 3.3.2.2.4.
3.3-1, 223	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no underground aluminum piping or piping components, or tanks in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 226	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no underground aluminum piping or piping components, or tanks in the Auxiliary Systems.
3.3-1, 227	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not used. There are no large or outdoor aluminum tanks in the Auxiliary Systems.
3.3-1, 228	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Not used. Stainless steel tanks exposed to air or condensation in the Auxiliary Systems are managed using different line items.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 229	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no stainless steel tanks exposed to soil or concrete in the Auxiliary Systems.
3.3-1, 230	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no stainless steel tanks exposed to soil or concrete in the Auxiliary Systems.
3.3-1, 231	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Not used. Stainless steel tanks exposed to air in the Auxiliary Systems are managed using different line items.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 232	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. This item is also used for heat exchanger shells and channel heads. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material in insulated stainless steel piping, piping components, and heat exchanger shells and channel heads exposed to uncontrolled air. Further evaluation is documented in Section 3.3.2.2.4.
3.3-1, 234	Aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMPs are used to manage loss of material in aluminum piping components exposed to indoor uncontrolled air Further evaluation is documented in Section 3.3.2.2.10.
3.3-1, 235	Metallic piping, piping components exposed to air-dry (internal)	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M24, "Compressed Air Monitoring"	No	Consistent with NUREG-2191. The Compressed Air Monitoring (B.2.3.14) AMP is used to manage loss of material in metallic piping and piping components exposed to a dry air internal environment.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 236	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no titanium components in the Auxiliary Systems.
3.3-1, 237	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not applicable. There are no titanium components in the Auxiliary Systems.
3.3-1, 238	Titanium heat exchanger tubes exposed to closed- cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no titanium components in the Auxiliary Systems.
3.3-1, 239	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed- cycle cooling water	None	None	No	Not applicable. There are no titanium components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 240	Aluminum heat exchanger components exposed to waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no aluminum heat exchanger components exposed to waste water in the Auxiliary Systems.
3.3-1, 241	Stainless steel, nickel alloy heat exchanger components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage the loss of material from stainless steel heat exchanger components exposed to indoor uncontrolled air. Further evaluation is documented in Section 3.3.2.2.4.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 242	Aluminum heat exchanger components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage the loss of material from aluminum heat exchanger components exposed to indoor uncontrolled air.. Further evaluation is documented in Section 3.3.2.2.10.
3.3-1, 245	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no insulated aluminum piping, piping components, or tanks in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 246	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Not used. There are no underground stainless steel or nickel alloy piping, piping, components, or tanks in the Auxiliary Systems.
3.3-1, 247	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no aluminum piping or piping components exposed to raw water or waste water in the Auxiliary Systems.
3.3-1, 248	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not used. There are no aluminum piping, piping components, or tanks exposed to borated water leakage in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 249	Steel heat exchanger tubes internal to components exposed to air-outdoor, air- indoor uncontrolled, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. This item is also used for piping and piping components. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage loss of material of steel piping, piping components, piping elements, and heat exchanger components exposed to uncontrolled air.
3.3-1, 250	Steel reactor coolant pump oil collection system tanks, piping, piping components exposed to lubricating oil (waste oil)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M32, "One-Time Inspection"	No	Not used. The Lubricating Oil Analysis (B.2.3.26) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material in steel piping exposed to lubricating oil per line item 3.3-1, 097.
3.3-1, 252	Aluminum piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no aluminum piping or piping components exposed to soil or concrete in the Auxiliary Systems.
3.3-1, 253	PVC piping, piping components exposed to raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water only)	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M27, "Fire Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage loss of material of plastic piping exposed to waste water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3-1, 254	Aluminum heat exchanger components exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage cracking of aluminum heat exchanger components exposed to indoor uncontrolled air. Further evaluation is documented in Section 3.3.2.2.8.
3.3-1, 255	Any material fire damper assemblies exposed to air	Loss of material due to general, pitting, crevice corrosion; cracking due to SCC; hardening, loss of strength, shrinkage due to elastomer degradation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.3.15) AMP is used to manage loss of material cracking, loss of strength, and shrinkage in fire damper assemblies. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 257	Steel, stainless steel, copper alloy heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.26) and One-Time Inspection (B.2.3.20) AMPs are used to manage reduction of heat transfer in copper alloy heat exchanger components exposed to lubricating oil.
3.3-1, 258	Metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 259	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no aluminum piping or piping components exposed to raw water in the Auxiliary Systems.
3.3-1, 260	Metallic HVAC closure bolting exposed to air, condensation	Loss of material due to general (where applicable), pitting, crevice corrosion; cracking due to SCC, loss of preload	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material and loss of preload of metallic HVAC closure bolting exposed to air condensation.
3.3-1, 261	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to closed- cycle cooling water, raw water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no titanium components in the Auxiliary Systems.
3.3-1, 262	Titanium piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M21A, "Closed Treated Water Systems," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no titanium components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 263	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no polymeric components in the Auxiliary Systems.
3.3-1, 265	Steel heat exchanger radiator tubes exposed to fuel oil	Reduction of heat transfer due to fouling	XI.M30, “Fuel Oil Chemistry,” and XI.M32, “One-Time Inspection”	No	Not applicable. There are no steel heat exchanger radiator tubes exposed to fuel oil in the Auxiliary Systems.
3.3-1, 266	Steel heat exchanger radiator tubes exposed to fuel oil	Reduction of heat transfer due to fouling	XI.M30, “Fuel Oil Chemistry,”	No	Not applicable. There are no steel heat exchanger radiator tubes exposed to fuel oil in the Auxiliary Systems.
3.3-1, 267	Subliming compound fireproofing/fire barriers (Thermolag ®, Darmatt™, 3M™ Interam™, and other similar materials) exposed to air	Loss of material, change in material properties, cracking, delamination, and separation	AMP XI.M26, “Fire Protection”	No	Not applicable. There are no subliming compounds (Thermo-lag®, Darmatt™, 3M™ Interam™, and other similar materials) exposed to air in the Auxiliary Systems.
3.3-1, 268	Cementitious coating fireproofing/fire barriers (Pyrocrete, BIO™ K-10 Mortar, Cafecote, and other similar materials) exposed to air	Loss of material, change in material properties, cracking, delamination, and separation	AMP XI.M26, “Fire Protection”	No	Consistent with NUREG-2191. The Fire Protection (B.2.3.15) AMP is used to manage cracking, loss of material, and separation for cementitious fire barriers exposed to air.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 269	Silicate fireproofing/fire barriers (Marinite®, Kaowool™, Cerafiber®, Cera® blanket, or other similar materials) exposed to air	Loss of material, change in material properties, cracking, delamination, and separation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.3.15) AMP is used to manage cracking, loss of material, and separation for calcium silicate board, ceramic fiber, board, and mat fire stops and wraps exposed to air.

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Flow element	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Flow element	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Heat exchanger (excess letdown channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (excess letdown channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	C
Heat exchanger (excess letdown channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	C
Heat exchanger (excess letdown shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.E1.AP-189	3.3-1, 046	B

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (excess letdown shell) (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	C
Heat exchanger (excess letdown tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (excess letdown tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (excess letdown tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (excess letdown tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (non-regenerative channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (non-regenerative channel head)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (non-regenerative channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	C
Heat exchanger (non-regenerative channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	C
Heat exchanger (non-regenerative shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.E1.AP-189	3.3-1, 046	B
Heat exchanger (non-regenerative shell) (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	C
Heat exchanger (non-regenerative tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (non-regenerative tubes)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2)	VII.E1.A-69	3.3-1, 003	B

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (non-regenerative tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (non-regenerative tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (non-regenerative tubesheet)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (non-regenerative tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (regenerative channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (regenerative channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	C
Heat exchanger (regenerative channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	C

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (regenerative shell)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (regenerative shell)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (regenerative shell) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	C
Heat exchanger (regenerative shell) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	C
Heat exchanger (regenerative tubes)	Pressure boundary	Stainless steel	Treated borated water (ext)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (regenerative tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (regenerative tubes)	Pressure boundary	Stainless steel	Treated borated water >140°F (ext)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (regenerative tubes)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (regenerative tubesheet)	Pressure boundary	Stainless steel	Treated borated water (ext)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (regenerative tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (regenerative tubesheet)	Pressure boundary	Stainless steel	Treated borated water >140°F (ext)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (regenerative tubesheet)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (seal water channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (seal water channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	C
Heat exchanger (seal water channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	C
Heat exchanger (seal water shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.E1.AP-189	3.3-1, 046	B

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (seal water shell) (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	C
Heat exchanger (seal water tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (seal water tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (seal water tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (seal water tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Instrument	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-48	3.3-1, 117	A
Instrument	Leakage boundary (spatial)	Glass	Treated borated water (int)	None	None	VII.J.AP-52	3.3-1, 117	A
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Instrument	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Instrument	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Instrument	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-82	3.3-1, 028	B A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-82	3.3-1, 028	B A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Piping	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-82	3.3-1, 028	B A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	A
Piping and piping components	Pressure boundary	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-82	3.3-1, 028	B A
Pump casing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump casing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Pump casing	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Pump casing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Pump casing	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Pump casing (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	A
Pump casing (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	A
Pump casing (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	A
Steel components	Leakage boundary (spatial)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Steel components	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Strainer	Filter	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Strainer	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Strainer	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Strainer	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Strainer	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-82	3.3-1, 028	B A
Strainer	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Strainer	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Strainer	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Tank (batching)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Tank (batching)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Tank (batching)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank (boric acid storage)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Tank (boric acid storage)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Tank (boric acid storage)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Tank (chemical mixing)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Tank (chemical mixing)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Tank (chemical mixing)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Tank (evaporator condensate demineralizer)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (evaporator condensate demineralizer)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Tank (evaporator condensate demineralizer)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Tank (monitor)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Tank (monitor)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Tank (monitor)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Tank (reactor makeup water)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.C3.A-401	3.3-1, 128	A
Tank (reactor makeup water)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.C3.A-401	3.3-1, 128	A
Tank (reactor makeup water)	Pressure boundary	Carbon steel	Concrete (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.C3.A-401	3.3-1, 128	A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (reactor makeup water)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.C3.A-413	3.3-1, 137	A
Tank (reactor makeup water)	Pressure boundary	Coating	Treated water (int)	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.F1.A-416	3.3-1, 138	B
Tank (volume control)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Tank (volume control)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Tank (volume control)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Thermowell	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Thermowell	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Thermowell	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Valve body	Pressure boundary	CASS	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-82	3.3-1, 028	B A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Valve body	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-82	3.3-1, 028	B A

Table 3.3.2-1: Chemical Volume and Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.3-1, 085	B A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C2.AP-209b	3.3-1, 004	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C2.AP-221b	3.3-1, 006	A
Flow element	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C2.AP-209b	3.3-1, 004	A

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C2.AP-221b	3.3-1, 006	A
Flow element	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Heat exchanger (component cooling channel head)	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Heat exchanger (component cooling channel head)	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	D
Heat exchanger (component cooling channel head)	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (component cooling channel head)	Pressure boundary	Coating	Raw water (int)	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.C1.A-416	3.3-1, 138	B
Heat exchanger (component cooling channel head) (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	C
Heat exchanger (component cooling shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-189	3.3-1, 046	B

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (component cooling shell) (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	C
Heat exchanger (component cooling tubes)	Heat transfer	Stainless steel	Raw water (int)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C3.AP-187	3.3-1, 042	B
Heat exchanger (component cooling tubes)	Heat transfer	Stainless steel	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	V.A.EP-96	3.2-1, 033	B
Heat exchanger (component cooling tubes)	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Heat exchanger (component cooling tubes)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (component cooling tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (component cooling tubesheet)	Pressure boundary	Coating	Raw water (int)	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.C1.A-416	3.3-1, 138	B
Heat exchanger (component cooling tubesheet)	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3-1, 038	B
Heat exchanger (component cooling tubesheet)	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (component cooling tubesheet)	Pressure boundary	Copper alloy	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3-1, 046	D
Heat exchanger (pressurizer liquid sample channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (pressurizer liquid sample channel head)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (pressurizer liquid sample channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	C
Heat exchanger (pressurizer liquid sample channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	C
Heat exchanger (pressurizer liquid sample shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-189	3.3-1, 046	B
Heat exchanger (pressurizer liquid sample shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (pressurizer liquid sample tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (pressurizer liquid sample tubes)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (pressurizer liquid sample tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (pressurizer liquid sample tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (pressurizer liquid sample tubesheet)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (pressurizer liquid sample tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (pressurizer steam sample channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (pressurizer steam sample channel head)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (pressurizer steam sample channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	C
Heat exchanger (pressurizer steam sample channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	C

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (pressurizer steam sample shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-189	3.3-1, 046	B
Heat exchanger (pressurizer steam sample shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (pressurizer steam sample tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (pressurizer steam sample tubes)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (pressurizer steam sample tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (pressurizer steam sample tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (pressurizer steam sample tubesheet)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (pressurizer steam sample tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (reactor coolant hot leg sample channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (reactor coolant hot leg sample channel head)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (reactor coolant hot leg sample channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	C
Heat exchanger (reactor coolant hot leg sample channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	C
Heat exchanger (reactor coolant hot leg sample shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (reactor coolant hot leg sample shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-189	3.3-1, 046	B
Heat exchanger (reactor coolant hot leg sample tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (reactor coolant hot leg sample tubes)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (reactor coolant hot leg sample tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (reactor coolant hot leg sample tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-41	3.2-1, 022	B A
Heat exchanger (reactor coolant hot leg sample tubesheet)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-118	3.3-1, 020	B A
Heat exchanger (reactor coolant hot leg sample tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (steam generator blowdown sample channel head)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4-1, 015	B A
Heat exchanger (steam generator blowdown sample channel head) (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	C
Heat exchanger (steam generator blowdown sample shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (steam generator blowdown sample shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-189	3.3-1, 046	B, 2
Heat exchanger (steam generator blowdown sample tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D, 2

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (steam generator blowdown sample tubes)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4-1, 085	B A
Heat exchanger (steam generator blowdown sample tubes)	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-85	3.4-1, 011	B A
Heat exchanger (steam generator blowdown sample tubesheet)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D, 2
Heat exchanger (steam generator blowdown sample tubesheet)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4-1, 085	B A
Heat exchanger (steam generator blowdown sample tubesheet)	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-85	3.4-1, 011	B A
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Instrument	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.C2.AP-127	3.3-1, 097	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Piping (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	A
Piping (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Pump casing	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B
Pump casing	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C2.A-50	3.3-1, 072	A
Pump casing	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B
Pump casing	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C2.A-50	3.3-1, 072	A
Steel components	Leakage boundary (spatial)	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Steel components	Pressure boundary	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank (surge)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (surge)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Tank (surge)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B
Thermowell	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Thermowell	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B
Valve body	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B
Valve body	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Leakage boundary (spatial)	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3-1, 046	B

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3-1, 046	B
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.AP-66	3.3-1, 009	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C2.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant Specific Notes

1. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage the wall thinning due to erosion aging effect.
2. Shell-side CC water in the steam generator blowdown sample cooler.

Table 3.3.2-3: Spent Fuel Cooling – Summary of Aging Management Evaluation

Table 3.3.2-3: Spent Fuel Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Filter	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Filter	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Filter	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A

Table 3.3.2-3: Spent Fuel Cooling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Flow element	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Heat exchanger (spent fuel pool channel head)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	D C
Heat exchanger (spent fuel pool channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	C
Heat exchanger (spent fuel pool channel head) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	C
Heat exchanger (spent fuel pool shell)	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	D

Table 3.3.2-3: Spent Fuel Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (spent fuel pool shell)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (spent fuel pool shell) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	C
Heat exchanger (spent fuel pool shell) (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	C
Heat exchanger (spent fuel pool tubes)	Heat transfer	Stainless steel	Raw water (ext)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3-1, 042	B
Heat exchanger (spent fuel pool tubes)	Heat transfer	Stainless steel	Treated borated water (int)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.A-101	3.3-1, 017	B A
Heat exchanger (spent fuel pool tubes)	Pressure boundary	Stainless steel	Raw water (ext)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	D
Heat exchanger (spent fuel pool tubes)	Pressure boundary	Stainless steel	Raw water (ext)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (spent fuel pool tubes)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	D C

Table 3.3.2-3: Spent Fuel Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (spent fuel pool tubesheet)	Pressure boundary	Stainless steel	Raw water (ext)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	D
Heat exchanger (spent fuel pool tubesheet)	Pressure boundary	Stainless steel	Raw water (ext)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (spent fuel pool tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	D C
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Instrument	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-3: Spent Fuel Cooling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Instrument	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A

Table 3.3.2-3: Spent Fuel Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Pump casing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Pump casing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Pump casing	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A

Table 3.3.2-3: Spent Fuel Cooling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Pump casing	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Steel components	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Strainer	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Strainer	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Strainer	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A

Table 3.3.2-3: Spent Fuel Cooling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (demineralizer)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Tank (demineralizer)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Tank (demineralizer)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Thermowell	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C2.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A

Table 3.3.2-3: Spent Fuel Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C2.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A

Table 3.3.2-3: Spent Fuel Cooling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A3.AP-79	3.3-1, 125	B A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

Plant Specific Notes

1. The Open Cycle Cooling Water (B.2.3.11) AMP is used to manage loss of material for the interior surfaces of the heat exchangers exposed to raw water.

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Compressor casing	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Compressor casing	Leakage boundary (spatial)	Gray cast iron	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Compressor casing	Leakage boundary (spatial)	Gray cast iron	Waste water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.E5.A-547	3.3-1, 072	A
Compressor casing	Leakage boundary (spatial)	Gray cast iron	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Compressor casing	Leakage boundary (spatial)	Gray cast iron	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Drain trap	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Drain trap	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Drain trap	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A
Drain trap	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Flow indicator	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Flow indicator	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Flow indicator	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Flow indicator	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-87	3.4-1, 085	B A
Flow indicator	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow indicator	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (waste evaporator distillate cooler channel head)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	C
Heat exchanger (waste evaporator distillate cooler channel head)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	C
Heat exchanger (waste evaporator distillate cooler channel head)	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	C
Heat exchanger (waste evaporator distillate cooler channel head)	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (waste evaporator distillate cooler shell)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (waste evaporator distillate cooler shell)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Heat exchanger (waste evaporator distillate cooler shell)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (waste evaporator distillate cooler shell)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (waste gas compressor channel head)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (waste gas compressor channel head)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-189	3.3-1, 046	B
Heat exchanger (waste gas compressor shell)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (waste gas compressor shell)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (waste gas compressor shell)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Heat exchanger (waste gas compressor shell)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Heat exchanger (waste gas compressor tubes)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-473a	3.3-1, 160	B
Heat exchanger (waste gas compressor tubes)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3-1, 046	D

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (waste gas compressor tubes)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C2.AP-32	3.3-1, 072	C
Heat exchanger (waste gas compressor tubes)	Pressure boundary	Copper alloy > 15% Zn	Waste water (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.A-473c	3.3-1, 160	A
Heat exchanger (waste gas compressor tubes)	Pressure boundary	Copper alloy > 15% Zn	Waste water (ext)	Loss of material	Selective Leaching (B.2.3.21)	VII.E5.A-547	3.3-1, 072	A
Heat exchanger (waste gas compressor tubes)	Pressure boundary	Copper alloy > 15% Zn	Waste water (ext)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-272	3.3-1, 095	A
Heat exchanger (waste gas compressor tubes)	Pressure boundary	Copper alloy > 15% Zn	Waste water (ext)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (waste gas compressor tubesheet)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-473a	3.3-1, 160	B
Heat exchanger (waste gas compressor tubesheet)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3-1, 046	D
Heat exchanger (waste gas compressor tubesheet)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C2.AP-32	3.3-1, 072	C

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (waste gas compressor tubesheet)	Pressure boundary	Copper alloy > 15% Zn	Waste water (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.A-473c	3.3-1, 160	A
Heat exchanger (waste gas compressor tubesheet)	Pressure boundary	Copper alloy > 15% Zn	Waste water (ext)	Loss of material	Selective Leaching (B.2.3.21)	VII.E5.A-547	3.3-1, 072	A
Heat exchanger (waste gas compressor tubesheet)	Pressure boundary	Copper alloy > 15% Zn	Waste water (ext)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-272	3.3-1, 095	A
Heat exchanger (waste gas compressor tubesheet)	Pressure boundary	Copper alloy > 15% Zn	Waste water (ext)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Instrument	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Instrument	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Instrument	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Level gauge	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Level gauge	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Level gauge	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Level gauge	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Level gauge	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Level gauge	Leakage boundary (spatial)	Copper alloy	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-272	3.3-1, 095	A
Level gauge	Leakage boundary (spatial)	Copper alloy	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Level gauge	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-48	3.3-1, 117	A
Level gauge	Leakage boundary (spatial)	Glass	Treated borated water (int)	None	None	VII.J.AP-52	3.3-1, 117	A
Level gauge	Leakage boundary (spatial)	Glass	Waste water (int)	None	None	VII.J.AP-277	3.3-1, 119	A
Level gauge	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Level gauge	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Level gauge	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Orifice	Leakage boundary (spatial)	Copper alloy > 15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Orifice	Leakage boundary (spatial)	Copper alloy > 15% Zn	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.AP-66	3.3-1, 009	A
Orifice	Leakage boundary (spatial)	Copper alloy > 15% Zn	Waste water (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.A-473c	3.3-1, 160	A
Orifice	Leakage boundary (spatial)	Copper alloy > 15% Zn	Waste water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.E5.A-547	3.3-1, 072	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Leakage boundary (spatial)	Copper alloy > 15% Zn	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-272	3.3-1, 095	A
Orifice	Leakage boundary (spatial)	Copper alloy > 15% Zn	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Orifice	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Orifice	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A
Orifice	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Piping	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Piping	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Piping	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A
Piping	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Piping	Pressure boundary	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Piping	Pressure boundary	Carbon steel	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Piping	Pressure boundary	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F2.AP-209c	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F2.AP-221c	3.3-1, 006	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Piping	Pressure boundary	Stainless steel	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A
Piping	Pressure boundary	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Pressure boundary	Carbon steel	Waste water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-34	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F2.AP-209c	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F2.AP-221c	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Piping and piping components	Structural integrity (attached)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Waste water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.E5.A-547	3.3-1, 072	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Pump casing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Pump casing	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Pump casing	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Pump casing	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Sight glass	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-48	3.3-1, 117	A
Sight glass	Leakage boundary (spatial)	Glass	Treated borated water (int)	None	None	VII.J.AP-52	3.3-1, 117	A
Sight glass	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Sight glass	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Sight glass	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Steel components	Leakage boundary (spatial)	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Steel components	Pressure boundary	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Strainer	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Strainer	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B
Strainer	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Strainer	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Strainer	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Strainer	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Strainer	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Strainer	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A
Strainer	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Tank (boric acid waste evaporator water separator tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Tank (boric acid waste evaporator water separator tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank (boric acid waste evaporator water separator tank)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Tank (reagent tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Tank (reagent tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Tank (reagent tank)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Tank (waste condensate polishing demineralizer)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Tank (waste condensate polishing demineralizer)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Tank (waste condensate polishing demineralizer)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Tank (waste condensate tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Tank (waste condensate tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Tank (waste condensate tank)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank (waste distillate tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Tank (waste distillate tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Tank (waste distillate tank)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Tank (waste evaporator concentrator)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Tank (waste evaporator concentrator)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Tank (waste evaporator concentrator)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Tank (waste evaporator distillate tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Tank (waste evaporator distillate tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Tank (waste evaporator distillate tank)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Tank (waste evaporator feed tank/heater)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Tank (waste evaporator feed tank/heater)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Tank (waste evaporator feed tank/heater)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank (waste holdup tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Tank (waste holdup tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Tank (waste holdup tank)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Tank (waste evaporator hot water expansion tank)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (waste evaporator hot water expansion tank)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Tank (waste evaporator hot water expansion tank)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Tank (waste evaporator hot water expansion tank)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Tank (waste gas moisture separator)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (waste gas moisture separator)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (waste gas moisture separator)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Tank (waste gas moisture separator)	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	B
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A
Valve body	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Valve body	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Valve body	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Leakage boundary (spatial)	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Valve body	Leakage boundary (spatial)	CASS	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A
Valve body	Leakage boundary (spatial)	CASS	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A
Valve body	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Valve body	Pressure boundary	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Valve body	Pressure boundary	Carbon steel	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Valve body	Pressure boundary	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Valve body	Pressure boundary	CASS	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A

Table 3.3.2-4: Waste Disposal System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	CASS	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F2.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	B A
Valve body	Pressure boundary	Stainless steel	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A
Valve body	Pressure boundary	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is enhanced to manage the wall thinning due to erosion aging effect.

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Carbon steel	Raw water (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-423	3.3-1, 142	A
Bolting	Mechanical closure	Carbon steel	Raw water (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Carbon steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-241	3.3-1, 109	B
Bolting	Mechanical closure	Carbon steel	Soil (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Raw water (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Raw water (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-423	3.3-1, 142	A
Bolting	Mechanical closure	Stainless steel	Raw water (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Soil (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Stainless steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-243	3.3-1, 108	B
Bolting	Mechanical closure	Stainless steel	Soil (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Expansion joint	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Expansion joint	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Expansion joint	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	B
Expansion joint	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Expansion joint	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3-1, 076	A
Expansion joint	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3-1, 082	A
Expansion joint	Pressure boundary	Elastomer	Raw water (int)	Hardening or loss of strength Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.AP-75	3.3-1, 085	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Expansion joint	Pressure boundary	Elastomer	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.G.AP-76	3.3-1, 096	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Expansion joint	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Expansion joint	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Flow element	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (aftercooler shell)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	C
Heat exchanger (aftercooler shell)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	C
Heat exchanger (aftercooler shell)	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Heat exchanger (aftercooler shell)	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Heat exchanger (blowdown vent condenser channel head)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (blowdown vent condenser channel head)	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (blowdown vent condenser channel head)	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	C
Heat exchanger (blowdown vent condenser channel head)	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Heat exchanger (blowdown vent condenser shell)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (blowdown vent condenser shell)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-778	3.3-1, 249	C
Heat exchanger (boric acid waste evaporator vacuum system end bell)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	C
Heat exchanger (boric acid waste evaporator vacuum system end bell)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	C

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (boric acid waste evaporator vacuum system end bell, tubesheet, tubes)	Pressure boundary	Stainless steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Heat exchanger (boric acid waste evaporator vacuum system end bell, tubesheet, tubes)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Heat exchanger (boric acid waste evaporator vacuum system shell)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	C
Heat exchanger (boric acid waste evaporator vacuum system shell)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	C
Heat exchanger (boric acid waste evaporator vacuum system shell)	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	D, 3 C
Heat exchanger (boric acid waste evaporator vacuum system tubesheet, tubes)	Pressure boundary	Stainless steel	Treated borated water (ext)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.AP-79	3.3-1, 125	D, 3 C
Heat exchanger (gas sample analyzer shell)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	C

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (gas sample analyzer shell)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	C
Heat exchanger (gas sample analyzer shell)	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Heat exchanger (gas sample analyzer shell)	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Heater/cooler (area cooler fins)	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Heater/cooler (area cooler tubes)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	C
Heater/cooler (area cooler tubes)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	C
Heater/cooler (area cooler tubes)	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heater/cooler (area cooler tubes)	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Hose reel	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.A-649	3.3-1, 197	A
Hose reel	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Hose reel	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Instrument	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Instrument	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Orifice	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Orifice	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Orifice	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Orifice	Throttle	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Orifice	Throttle	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Piping	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Piping	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Piping	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	B
Piping	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Carbon steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	B
Piping	Pressure boundary	Carbon steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	B
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Piping	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Carbon steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump casing	Pressure boundary	Coating	Raw water (int)	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.C1.A-416	3.3-1, 138	B
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Pump casing	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Pump casing	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Sight glass	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Sight glass	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Sight glass	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Sight glass	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Sight glass	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Sight glass	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Sight glass	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Sight glass	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Sight glass	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	B
Sight glass	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Sight glass	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3-1, 034	B
Sight glass	Pressure boundary	Glass	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-48	3.3-1, 117	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Sight glass	Pressure boundary	Glass	Raw water (int)	None	None	VII.J.AP-50	3.3-1, 117	A
Sight glass	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Sight glass	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Sight glass	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Steel components	Leakage boundary (spatial)	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Steel components	Pressure boundary	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Strainer	Filter	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Strainer	Filter	Carbon steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	B
Strainer	Filter	Carbon steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Strainer	Filter	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Strainer	Filter	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3-1, 072	A
Strainer	Filter	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	B

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Strainer	Filter	Gray cast iron	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Strainer	Filter	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Strainer	Filter	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Strainer	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Strainer	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Strainer	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Strainer	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Strainer	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Strainer	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Strainer	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	B
Strainer	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Strainer	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Strainer	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Strainer	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3-1, 072	A
Strainer	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	B
Strainer	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Strainer	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Strainer	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Strainer	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Thermowell	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Thermowell	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Thermowell	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	B
Thermowell	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Thermowell	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Thermowell	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Thermowell	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Thermowell	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Valve body	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Valve body	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 2
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	B
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	CASS	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Valve body	Pressure boundary	CASS	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3-1, 034	B
Valve body	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Raw water (int)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3-1, 160	B
Valve body	Pressure boundary	Copper alloy > 15% Zn	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-47	3.3-1, 072	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3-1, 034	B
Valve body	Pressure boundary	Copper alloy > 15% Zn	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3-1, 072	A

Table 3.3.2-5: Service Water System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	B
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	B
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant Specific Notes

1. The Open Cycle Cooling Water (B.2.3.11) AMP is used to manage wall thinning due to erosion for the interior surfaces of components within the service water system exposed to raw water within the scope of the GL 89-13 program.
2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage wall thinning due to erosion for the interior surfaces of components within the service water system exposed to raw water not within the scope of the GL 89-13 program (that is non-essential loads that can be automatically from essential loads or discharge/return components).
3. Boric acid evaporator vacuum system heat exchanger (HX-702) shell contains tubes (coil) that are in the service water pressure boundary and cannot be isolated. Conservatively, any condensation or coil leakage inside the shell could leak onto safety-related SSCs in the vicinity with shell degradation due to aging.

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Accumulator (halon)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Fire Protection (B.2.3.15)	VII.G.AP-150	3.3-1, 058	A
Accumulator (halon)	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Carbon steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-241	3.3-1, 109	B
Bolting	Mechanical closure	Carbon steel	Soil (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Mechanical closure	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Soil (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-243	3.3-1, 108	B
Bolting	Mechanical closure	Stainless steel	Soil (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Compressor casing	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Compressor casing	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (int)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3-1, 136	C
Expansion joint	Pressure boundary	Neoprene	Air – indoor uncontrolled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3-1, 076	A
Expansion joint	Pressure boundary	Neoprene	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3-1, 082	A
Expansion joint	Pressure boundary	Neoprene	Raw water (int)	Hardening or loss of strength Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.G.AP-75	3.3-1, 085	A
Expansion joint	Pressure boundary	Neoprene	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.G.AP-76	3.3-1, 096	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.AP-209b	3.3-1, 004	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.AP-221b	3.3-1, 006	A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Expansion joint	Pressure boundary	Stainless steel	Diesel exhaust (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.AP-128	3.3-1, 083	A
Expansion joint	Pressure boundary	Stainless steel	Diesel exhaust (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.AP-104	3.3-1, 088	A
Fire hydrant	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-149	3.3-1, 063	A
Fire hydrant	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-149	3.3-1, 063	A
Fire hydrant	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Fire hydrant	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-149	3.3-1, 063	A
Fire hydrant	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Flame arrestor	Fire prevention	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Flame arrestor	Fire prevention	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.G.AP-234	3.3-1, 070	B A
Flame arrestor	Fire prevention	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26)	VII.G.AP-127	3.3-1, 097	A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
					One-Time Inspection (B.2.3.20)			
Hose reel	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Hose reel	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Hose reel	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
Instrument	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Instrument	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	A
Nozzle	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	A
Nozzle	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Nozzle	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Nozzle	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Nozzle	Pressure boundary	Copper alloy > 15% Zn	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.AP-66	3.3-1, 009	A
Nozzle	Spray	Copper alloy	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	A
Nozzle	Spray	Copper alloy	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Nozzle	Spray	Copper alloy > 15% Zn	Air – indoor uncontrolled (int)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-404	3.3-1, 131	A
Orifice	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Orifice	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Orifice	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
Orifice	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Orifice	Throttle	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Orifice	Throttle	Carbon steel	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
Orifice	Throttle	Carbon steel	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Concrete (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	B
Piping	Pressure boundary	Carbon steel	Concrete (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	B
Piping	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.G.AP-234	3.3-1, 070	B A
Piping	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Piping	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Piping	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
Piping	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Carbon steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	B
Piping	Pressure boundary	Carbon steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	B
Piping	Pressure boundary	Coating (cementitious)	Raw water (int)	Loss of coating or lining integrity (cementitious)	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.G.A-416	3.3-1, 138	B
Piping	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	A
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
Piping	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Gray cast iron	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	B
Piping	Pressure boundary	Gray cast iron	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	B
Piping	Pressure boundary	Gray cast iron	Soil (ext)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-02	3.3-1, 072	A
Piping	Pressure boundary	Stainless steel	Diesel exhaust (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.AP-128	3.3-1, 083	A
Piping	Pressure boundary	Stainless steel	Diesel exhaust (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.AP-104	3.3-1, 088	A
Piping (halon)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Fire Protection (B.2.3.15)	VII.G.AP-150	3.3-1, 058	A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Pump casing	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	A
Pump casing	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
RCP oil collection	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
RCP oil collection	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.G.AP-127	3.3-1, 097	C
RCP oil collection	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	C
RCP oil collection	Pressure boundary	Copper alloy > 15% Zn	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.AP-66	3.3-1, 009	A
RCP oil collection	Pressure boundary	Copper alloy > 15% Zn	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.G.AP-133	3.3-1, 099	C
Sight glass	Pressure boundary	Glass	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-48	3.3-1, 117	A
Sight glass	Pressure boundary	Glass	Lubricating oil (int)	None	None	VII.J.AP-15	3.3-1, 117	A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Silencer	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.AP-209b	3.3-1, 004	A
Silencer	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.AP-221b	3.3-1, 006	A
Silencer	Pressure boundary	Stainless steel	Diesel exhaust (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.AP-128	3.3-1, 083	A
Silencer	Pressure boundary	Stainless steel	Diesel exhaust (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Silencer	Pressure boundary	Stainless steel	Diesel exhaust (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.AP-104	3.3-1, 088	A
Steel components	Pressure boundary	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Strainer	Filter	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Strainer	Filter	Carbon steel	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
Strainer	Filter	Carbon steel	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Strainer	Filter	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Strainer	Filter	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	A
Strainer	Filter	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Strainer	Filter	Gray cast iron	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Strainer	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Strainer	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Strainer	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
Strainer	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Strainer	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Strainer	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Strainer	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	A
Strainer	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
Strainer	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Tank (accumulator)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (accumulator)	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Tank (accumulator)	Pressure boundary	Carbon steel	Raw water (int)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3-1, 136	A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (diesel fire pump fuel oil day)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (diesel fire pump fuel oil day)	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18)	VII.G.AP-234a	3.3-1, 070	B
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.G.AP-234	3.3-1, 070	B A
Valve body	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	CASS	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18)	VII.H1.AP-136	3.3-1, 071	B A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
					One Time Inspection (B.2.3.20)			
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Gas (int)	None	None	VII.J.AP-9	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	A
Valve body	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Gas (int)	None	None	VII.J.AP-9	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Raw water (int)	Cracking	Fire Water System (B.2.3.16)	VII.C1.A-473b	3.3-1, 160	E, 2
Valve body	Pressure boundary	Copper alloy > 15% Zn	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-47	3.3-1, 072	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-6: Fire Protection System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Gray cast iron	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Gray cast iron	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	B
Valve body	Pressure boundary	Gray cast iron	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	B
Valve body	Pressure boundary	Gray cast iron	Soil (ext)	Loss of material	Selective Leaching (B.2.3.21)	VII.C3.A-02	3.3-1, 072	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-55	3.3-1, 066	A
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body (halon)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Fire Protection (B.2.3.15)	VII.G.AP-150	3.3-1, 058	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

Plant Specific Notes

1. The Fire Water System (B.2.3.16) AMP is used to manage the wall thinning due to erosion aging effect for components exposed to raw water.
2. The Fire Water System (B.2.3.16) AMP is used to manage the cracking aging effect for copper alloy >15% Zn components exposed to raw water .

Table 3.3.2-7: Heating Steam System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Heater/cooler	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	C
Heater/cooler	Leakage boundary (spatial)	Copper alloy	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.F3.A-566	3.3-1, 169	D C
Heater/cooler	Leakage boundary (spatial)	Copper alloy	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	C
Heater/cooler (insulated)	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	C
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-71	3.4-1, 014	B A

Table 3.3.2-7: Heating Steam System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-15	3.4-1, 005	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A
Piping (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-34	3.3-1, 002	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4-1, 033	A

Table 3.3.2-7: Heating Steam System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-16	3.4-1, 005	A
Steam trap	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Steam trap	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Steam trap	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Steam trap	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A
Steam trap	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.S-16	3.3-1, 078	A
Steam trap	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4-1, 033	A

Table 3.3.2-7: Heating Steam System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steam trap	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Steam trap	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Steam trap	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-16	3.4-1, 005	A
Steel components	Leakage boundary (spatial)	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Strainer	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Strainer	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4-1, 033	A
Strainer	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-71	3.4-1, 014	B A
Strainer	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Strainer	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-15	3.4-1, 005	A
Strainer	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4-1, 033	A

Table 3.3.2-7: Heating Steam System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Strainer	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Strainer	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Strainer	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-16	3.4-1, 005	A
Tank (cond return pump cond receiver)	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (cond return pump cond receiver)	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4-1, 033	A
Tank (cond return pump cond receiver)	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Tank (cond return pump cond receiver)	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Tank (cond return pump cond receiver)	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-16	3.4-1, 005	A
Valve body	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-7: Heating Steam System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Leakage boundary (spatial)	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-71	3.4-1, 014	B A
Valve body	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-15	3.4-1, 005	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 005	A
Valve body	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Leakage boundary (spatial)	Copper alloy	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.F3.A-566	3.3-1, 169	B A
Valve body	Leakage boundary (spatial)	Copper alloy	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Copper alloy	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-101	3.4-1, 016	B A

Table 3.3.2-7: Heating Steam System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Copper Alloy > 15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Valve body	Leakage boundary (spatial)	Copper Alloy > 15% Zn	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.AP-66	3.3-1, 009	A
Valve body	Leakage boundary (spatial)	Copper Alloy > 15% Zn	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.F3.A-566	3.3-1, 169	B A
Valve body	Leakage boundary (spatial)	Copper Alloy > 15% Zn	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Copper Alloy > 15% Zn	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-101	3.4-1, 016	B A
Valve body	Leakage boundary (spatial)	Copper Alloy > 15% Zn	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.E.SP-55	3.4-1, 033	A
Valve body	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4-1, 033	A
Valve body	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-71	3.4-1, 014	B A

Table 3.3.2-7: Heating Steam System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-15	3.4-1, 005	A
Valve body	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4-1, 033	A
Valve body	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Valve body	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-16	3.4-1, 005	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Air motor	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Air motor	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Air motor	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – outdoor (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Drain trap	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-209b	3.3-1, 004	A
Drain trap	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-221b	3.3-1, 006	A
Drain trap	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H1.AP-209c	3.3-1, 004	A
Drain trap	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H1.AP-221c	3.3-1, 006	A
Expansion joint	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Expansion joint	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Expansion joint	Pressure boundary	Carbon steel	Diesel exhaust (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.AP-104	3.3-1, 088	A
Expansion joint	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Expansion joint	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	B
Expansion joint	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3-1, 076	A
Expansion joint	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3-1, 082	A
Expansion joint	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Hardening or loss of strength Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.A-504	3.3-1, 085	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Expansion joint	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.AP-103	3.3-1, 096	A
Expansion joint	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-209b	3.3-1, 004	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-221b	3.3-1, 006	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H1.AP-209c	3.3-1, 004	A
Expansion joint	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H1.AP-221c	3.3-1, 006	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Expansion joint	Pressure boundary	Stainless steel	Diesel exhaust (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.AP-128	3.3-1, 083	A
Expansion joint	Pressure boundary	Stainless steel	Diesel exhaust (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.AP-104	3.3-1, 088	A
Expansion joint	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Fan housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Fan housing	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Filter	Filter	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Filter	Filter	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Filter	Filter	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Filter	Filter	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Filter	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Filter	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Filter	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Filter	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Filter	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Flame arrestor	Fire prevention	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flame arrestor	Fire prevention	Gray cast iron	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-209b	3.3-1, 004	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-221b	3.3-1, 006	A
Flow element	Pressure boundary	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-136	3.3-1, 071	B A
Flow element	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Flow indicator	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Flow indicator	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (channel head) (G-05 GT lube oil coolers)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (channel head) (G-05 GT lube oil coolers)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	D
Heat exchanger (G-01/02 EDG coolant channel head)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (G-01/02 EDG coolant channel head)	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Heat exchanger (G-01/02 EDG coolant channel head)	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-183	3.3-1, 038	B
Heat exchanger (G-01/02 EDG coolant channel head)	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (G-01/02 EDG coolant shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (G-01/02 EDG coolant shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	D

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (G-01/02 EDG coolant tubes)	Heat transfer	Stainless steel	Raw water (int)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.H2.AP-187	3.3-1, 042	B
Heat exchanger (G-01/02 EDG coolant tubes)	Heat transfer	Stainless steel	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-188	3.3-1, 050	B
Heat exchanger (G-01/02 EDG coolant tubes)	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	D
Heat exchanger (G-01/02 EDG coolant tubes)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (G-01/02 EDG coolant tubes)	Pressure boundary	Stainless steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	D
Heat exchanger (G-01/02 EDG coolant tubesheet)	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Heat exchanger (G-01/02 EDG coolant tubesheet)	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-183	3.3-1, 038	B
Heat exchanger (G-01/02 EDG coolant tubesheet)	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (G-01/02 EDG coolant tubesheet)	Pressure boundary	Carbon steel	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	D
Heat exchanger (G-01/02/03/04 EDG lube oil coolers channel head)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (G-01/02/03/04 EDG lube oil coolers channel head)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	D
Heat exchanger (G-01/02/03/04 EDG lube oil coolers shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (G-01/02/03/04 EDG lube oil coolers shell)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3-1, 098	A
Heat exchanger (G-01/02/03/04 EDG lube oil coolers tubes)	Heat transfer	Copper alloy	Lubricating oil (ext)	Reduction of heat transfer	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.A-791	3.3-1, 257	A
Heat exchanger (G-01/02/03/04 EDG lube oil coolers tubes)	Heat transfer	Copper alloy	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-205	3.3-1, 050	B
Heat exchanger (G-01/02/03/04 EDG lube oil coolers tubes)	Pressure boundary	Copper alloy	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	C
Heat exchanger (G-01/02/03/04 EDG lube oil coolers tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-199	3.3-1, 046	D

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (G-01/02/03/04 EDG lube oil coolers tubesheet)	Pressure boundary	Carbon steel	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3-1, 098	C
Heat exchanger (G-01/02/03/04 EDG lube oil coolers tubesheet)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	D
Heat exchanger (G-03/04 EDG radiator fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F4.A-788c	3.3-1, 254	A
Heat exchanger (G-03/04 EDG radiator fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F4.A-771c	3.3-1, 242	A
Heat exchanger (G-03/04 EDG radiator fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F4.A-419	3.3-1, 096a	C
Heat exchanger (G-03/04 EDG radiator tubes)	Heat transfer	Copper alloy > 15% Zn	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F4.A-419	3.3-1, 096a	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (G-03/04 EDG radiator tubes)	Heat transfer	Copper alloy > 15% Zn	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-205	3.3-1, 050	B
Heat exchanger (G-03/04 EDG radiator tubes)	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	C
Heat exchanger (G-03/04 EDG radiator tubes)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-473a	3.3-1, 160	D
Heat exchanger (G-03/04 EDG radiator tubes)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-199	3.3-1, 046	D
Heat exchanger (G-03/04 EDG radiator tubes)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.H2.AP-43	3.3-1, 072	C
Heat exchanger (G-03/04 EDG radiator water box)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (G-03/04 EDG radiator water box)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	D
Heat exchanger (G-05 GT cooling water tubes)	Heat transfer	Copper alloy	Air – outdoor (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F4.A-419	3.3-1, 096a	A
Heat exchanger (G-05 GT cooling water tubes)	Heat transfer	Copper alloy	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-205	3.3-1, 050	B

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (G-05 GT cooling water tubes)	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (G-05 GT cooling water tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-199	3.3-1, 046	D
Heat exchanger (G-05 GT low/high pressure air coolers coils)	Heat transfer	Copper alloy	Air – indoor uncontrolled (int)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F4.A-419	3.3-1, 096a	A
Heat exchanger (G-05 GT low/high pressure air coolers coils)	Heat transfer	Copper alloy	Air – outdoor (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F4.A-419	3.3-1, 096a	A
Heat exchanger (G-05 GT low/high pressure air coolers coils)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (G-05 GT low/high pressure air coolers coils)	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (G-05 GT lube oil coolers channel head)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (G-05 GT lube oil coolers channel head)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	D

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (G-05 GT lube oil coolers shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (G-05 GT lube oil coolers shell)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3-1, 098	A
Heat exchanger (G-05 GT lube oil coolers tubes)	Heat transfer	Copper alloy	Lubricating oil (ext)	Reduction of heat transfer	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.A-791	3.3-1, 257	A
Heat exchanger (G-05 GT lube oil coolers tubes)	Heat transfer	Copper alloy	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-205	3.3-1, 050	B
Heat exchanger (G-05 GT lube oil coolers tubes)	Pressure boundary	Copper alloy	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	C
Heat exchanger (G-05 GT lube oil coolers tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-199	3.3-1, 046	D
Heat exchanger (G-05 GT lube oil coolers tubesheet)	Pressure boundary	Carbon steel	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3-1, 098	C
Heat exchanger (G-05 GT lube oil coolers tubesheet)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	D

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Instrument	Pressure boundary	Glass	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-48	3.3-1, 117	A
Instrument	Pressure boundary	Glass	Treated water (int)	None	None	VII.J.AP-51	3.3-1, 117	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-221b	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-136	3.3-1, 071	B A
Orifice	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	A
Orifice	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Orifice	Throttle	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-136	3.3-1, 071	B A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Throttle	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	A
Orifice	Throttle	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Piping	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Leakage boundary (spatial)	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Piping	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Diesel exhaust (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.AP-104	3.3-1, 088	A
Piping	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Piping	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Piping	Pressure boundary	Carbon steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	B
Piping	Pressure boundary	Carbon steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	B
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	B
Piping	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Copper alloy	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-132	3.3-1, 069	B A
Piping	Pressure boundary	Copper alloy	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	A
Piping	Pressure boundary	Plastic	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-268	3.3-1, 119	A
Piping	Pressure boundary	Plastic	Air – indoor uncontrolled (int)	None	None	VII.J.AP-268	3.3-1, 119	A
Piping	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-136	3.3-1, 071	B A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	A
Piping and piping components	Pressure boundary	Carbon steel	Diesel exhaust (int)	Cumulative Fatigue Damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-34	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B
Pump casing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Pump casing	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Pump casing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	B

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Pump casing	Pressure boundary	Gray cast iron	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Pump casing	Pressure boundary	Gray cast iron	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Pump casing	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	B
Pump casing	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C2.A-50	3.3-1, 072	A
Sight glass	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Sight glass	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Sight glass	Pressure boundary	Glass	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-48	3.3-1, 117	A
Sight glass	Pressure boundary	Glass	Fuel oil (int)	None	None	VII.J.AP-49	3.3-1, 117	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Silencer	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Silencer	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Silencer	Pressure boundary	Carbon steel	Diesel exhaust (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.AP-104	3.3-1, 088	A
Silencer	Pressure boundary	Carbon steel	Diesel exhaust (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-34	3.3-1, 002	A
Strainer	Filter	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Strainer	Filter	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Strainer	Filter	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	B

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Strainer	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.A-451b	3.3-1, 189	A
Strainer	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.A-763b	3.3-1, 234	A
Strainer	Pressure boundary	Aluminum	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H2.AP-129	3.3-1, 071	B A
Strainer	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Strainer	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Strainer	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Strainer	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	B

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank (EDG coolant expansion)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (EDG coolant expansion)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	B
Tank (EDG day)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (EDG day)	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Tank (EDG dry starting air receivers)	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Tank (EDG dry starting air receivers)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (EDG fuel oil storage)	Pressure boundary	Carbon steel	Concrete (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	B
Tank (EDG fuel oil storage)	Pressure boundary	Carbon steel	Concrete (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	B

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (EDG fuel oil storage)	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Tank (EDG starting air receivers)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (EDG starting air receivers)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Tank (emergency fuel oil storage)	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Tank (emergency fuel oil storage)	Pressure boundary	Carbon steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	B
Tank (emergency fuel oil storage)	Pressure boundary	Carbon steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	B
Tank (fuel oil storage)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-401	3.3-1, 128	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (fuel oil storage)	Pressure boundary	Carbon steel	Concrete (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-401	3.3-1, 128	A
Tank (fuel oil storage)	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-401	3.3-1, 128	A
Tank (fuel oil storage)	Pressure boundary	Coating	Fuel oil (int)	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.H1.A-416	3.3-1, 138	B
Tank (GT fuel oil)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (GT fuel oil)	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Tank (GT glycol expansion)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (GT glycol expansion)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	B

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank (GT instrument air receiver)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (GT instrument air receiver)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Turbine casing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Turbine casing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Turbo-charger	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.A-451b	3.3-1, 189	A
Turbo-charger	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.A-763b	3.3-1, 234	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Turbo-charger	Pressure boundary	Aluminum	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.A-451c	3.3-1, 189	A
Turbo-charger	Pressure boundary	Aluminum	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H2.A-763c	3.3-1, 234	A
Turbo-charger	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Turbo-charger	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Valve body	Leakage boundary (spatial	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Valve body	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Valve body	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Valve body	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3-1, 045	B
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-209b	3.3-1, 004	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Copper alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-132	3.3-1, 069	B A
Valve body	Pressure boundary	Copper alloy	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	A
Valve body	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-199	3.3-1, 046	B
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-132	3.3-1, 069	B A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	A
Valve body	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Gray cast iron	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	B A
Valve body	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-221b	3.3-1, 006	A

Table 3.3.2-8: Emergency Power System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H1.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.H1.AP-221c	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Fuel oil (int)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One Time Inspection (B.2.3.20)	VII.H1.AP-136	3.3-1, 071	B A
Valve body	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

Plant Specific Notes

1. The Open Cycle Cooling Water (B.2.3.11) AMP is used to manage the wall thinning due to erosion aging effect for components exposed to raw water.

Table 3.3.2-9: Containment Ventilation – Summary of Aging Management Evaluation

Table 3.3.2-9: Containment Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Boot seal	Pressure boundary	Elastomer	Air – dry (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.A-504	3.3-1, 085	A
Boot seal	Pressure boundary	Elastomer	Air – dry (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.AP-103	3.3-1, 096	C
Boot seal	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3-1, 076	A
Boot seal	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3-1, 082	A

Table 3.3.2-9: Containment Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Damper housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Damper housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.A-778	3.3-1, 249	C
Duct	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Duct	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.A-778	3.3-1, 249	C
Duct	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Duct	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.A-778	3.3-1, 249	C
Fan housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Fan housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.A-778	3.3-1, 249	C
Filter	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-9: Containment Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Filter	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.A-778	3.3-1, 249	C
Heat exchanger (containment vent cooling coils)	Heat transfer	Copper alloy	Condensation (ext)	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-716	3.3-1, 151	A
Heat exchanger (containment vent cooling coils)	Heat transfer	Copper alloy	Raw water (int)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3-1, 042	B
Heat exchanger (containment vent cooling coils)	Pressure boundary	Copper alloy	Condensation (ext)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (containment vent cooling coils)	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3-1, 038	B
Heat exchanger (containment vent cooling coils)	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (containment vent cooling tubesheet)	Pressure boundary	Copper alloy	Condensation (ext)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (containment vent cooling tubesheet)	Pressure boundary	Copper alloy	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3-1, 038	B
Heat exchanger (containment vent cooling tubesheet)	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (containment vent cooling waterbox)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-209b	3.3-1, 004	C

Table 3.3.2-9: Containment Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (containment vent cooling waterbox)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-770b	3.3-1, 241	A
HVAC Closure Bolting	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-794	3.3-1, 260	A
HVAC Closure Bolting	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-794	3.3-1, 260	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.A-778	3.3-1, 249	C
Piping	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.A-778	3.3-1, 249	C

Table 3.3.2-9: Containment Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-221b	3.3-1, 006	A
Steel components	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Thermowell	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Thermowell	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.A-778	3.3-1, 249	C
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.A-778	3.3-1, 249	C
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.AP-66	3.3-1, 009	A

Table 3.3.2-9: Containment Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-221b	3.3-1, 006	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant Specific Notes

1. The Open Cycle Cooling Water (B.2.3.11) AMP is used to manage loss of material for the interior surfaces of the heat exchangers exposed to raw water.

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Carbon steel	Air – outdoor (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Damper housing	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	C
Damper housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Damper housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	C
Damper housing	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Duct	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	C
Duct	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Duct	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	C
Duct	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Duct	Pressure boundary	Elastomer	Air – indoor controlled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3-1, 076	A
Duct	Pressure boundary	Elastomer	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3-1, 082	A

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Duct	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.A-504	3.3-1, 085	C
Duct	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.AP-103	3.3-1, 096	C
Fan housing	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	C
Fan housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Fan housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	C
Fan housing	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Filter	Filter	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	C
Filter	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	C

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Filter	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Filter	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	C
Filter	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor controlled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Flow element	Leakage boundary (spatial)	Stainless steel	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Flow element	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Flow element	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Flow element	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Flow element	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (Auxiliary feedwater pump room cooler housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (Auxiliary feedwater pump room cooler housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-778	3.3-1, 249	C
Heat exchanger (Auxiliary feedwater pump room cooler tubes)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (Auxiliary feedwater pump room cooler tubes)	Pressure boundary	Copper alloy	Raw water (int)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3-1, 038	B
Heat exchanger (Auxiliary feedwater pump room cooler tubes)	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (containment spray area cooling coil fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.A-788c	3.3-1, 254	A
Heat exchanger (containment spray area cooling coil fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.A-771c	3.3-1, 242	A
Heat exchanger (containment spray area cooling coil fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F2.A-419	3.3-1, 096a	A

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (containment spray area cooling coil housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (containment spray area cooling coil housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-778	3.3-1, 249	C
Heat exchanger (containment spray area cooling coil tubes)	Heat transfer	Copper alloy	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-419	3.3-1, 096a	A
Heat exchanger (containment spray area cooling coil tubes)	Heat transfer	Copper alloy	Raw water (int)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3-1, 042	B
Heat exchanger (containment spray area cooling coil tubes)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (containment spray area cooling coil tubes)	Pressure boundary	Copper alloy	Raw water (int)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3-1, 038	B
Heat exchanger (containment spray area cooling coil tubes)	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (CSR chilled water cooling coil tubes)	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (CSR chilled water cooling coil tubes)	Leakage boundary (spatial)	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.E1.AP-199	3.3-1, 046	D
Heat exchanger (MCR chilled water cooling coil fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.A-788c	3.3-1, 254	A
Heat exchanger (MCR chilled water cooling coil fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.A-771c	3.3-1, 242	A
Heat exchanger (MCR chilled water cooling coil fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.A-419	3.3-1, 096a	A
Heat exchanger (MCR chilled water cooling coil housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (MCR chilled water cooling coil housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-778	3.3-1, 249	C
Heat exchanger (MCR chilled water cooling coil tubes)	Heat transfer	Copper alloy	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-419	3.3-1, 096a	A
Heat exchanger (MCR chilled water cooling coil tubes)	Heat transfer	Copper alloy	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-205	3.3-1, 050	B

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (MCR chilled water cooling coil tubes)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (MCR chilled water cooling coil tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.E1.AP-199	3.3-1, 046	D
Heat exchanger (MCR/computer room water duct heater housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (MCR/computer room water duct heater housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-778	3.3-1, 249	C
Heat exchanger (MCR/computer room water duct heater tubes)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (MCR/computer room water duct heater tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.E1.AP-199	3.3-1, 046	D
Heat exchanger (PAB battery room vent cooler fins)	Heat transfer	Copper alloy	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F2.A-419	3.3-1, 096a	A
Heat exchanger (PAB battery room vent cooler housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (PAB battery room vent cooler housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-778	3.3-1, 249	C
Heat exchanger (PAB battery room vent cooler tubes)	Heat transfer	Stainless steel	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F2.A-419	3.3-1, 096a	A
Heat exchanger (PAB battery room vent cooler tubes)	Heat transfer	Stainless steel	Raw water (int)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3-1, 042	B
Heat exchanger (PAB battery room vent cooler tubes)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.AP-209c	3.3-1, 004	A
Heat exchanger (PAB battery room vent cooler tubes)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.AP-221c	3.3-1, 006	A
Heat exchanger (PAB battery room vent cooler tubes)	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	D
Heat exchanger (PAB battery room vent cooler tubes)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (RHR pump room cooling coil fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.A-788c	3.3-1, 254	A

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (RHR pump room cooling coil fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.A-771c	3.3-1, 242	A
Heat exchanger (RHR pump room cooling coil fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F2.A-419	3.3-1, 096a	A
Heat exchanger (RHR pump room cooling coil housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger (RHR pump room cooling coil housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-778	3.3-1, 249	C
Heat exchanger (RHR pump room cooling coil tubes)	Heat transfer	Copper alloy	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-419	3.3-1, 096a	A
Heat exchanger (RHR pump room cooling coil tubes)	Heat transfer	Copper alloy	Raw water (int)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3-1, 042	B
Heat exchanger (RHR pump room cooling coil tubes)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (RHR pump room cooling coil tubes)	Pressure boundary	Copper alloy	Raw water (int)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3-1, 038	B

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (RHR pump room cooling coil tubes)	Pressure boundary	Copper alloy	Raw water (int)	Wall thinning – erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Humidifier	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	C
Humidifier	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-778	3.3-1, 249	C
HVAC closure bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-794	3.3-1, 260	A
HVAC closure bolting	Mechanical closure	Carbon steel	Air – outdoor (ext)	Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-794	3.3-1, 260	A
HVAC closure bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking Loss of material Loss of preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-794	3.3-1, 260	A
Instrument	Pressure boundary	Glass	Air – indoor controlled (ext)	None	None	VII.J.AP-48	3.3-1, 117	A
Instrument	Pressure boundary	Glass	Treated water (int)	None	None	VII.J.AP-166	3.3-1, 117	A
Piping	Leakage boundary (spatial)	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage boundary (spatial)	Carbon steel	Condensation (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.A-778	3.3-1, 249	C
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B
Piping	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Piping	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Piping	Leakage boundary (spatial)	PVC	Condensation (int)	None	None	VII.J.AP-269	3.3-1, 119	A
Piping	Leakage boundary (spatial)	PVC	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.A-787d	3.3-1, 253	A
Piping	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B
Piping	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.AP-209c	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.AP-221c	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor controlled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.AP-209c	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F1.AP-221c	3.3-1, 006	A
Pump casing	Leakage boundary (spatial)	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A
Pump casing	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B
Pump casing	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A
Pump casing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B
Strainer	Filter	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Strainer	Leakage boundary (spatial)	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A
Strainer	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B
Strainer	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A
Strainer	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B
Tank (expansion tank T-78)	Leakage boundary (spatial)	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A
Tank (expansion tank T-78)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B
Tank (expansion tank T-79)	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A
Tank (expansion tank T-79)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B
Thermowell	Leakage boundary (spatial)	Stainless steel	Air – indoor controlled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Thermowell	Leakage boundary (spatial)	Stainless steel	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Thermowell	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Thermowell	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Thermowell	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Thermowell	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Thermowell	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Thermowell	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Valve body	Leakage boundary (spatial)	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B
Valve body	Leakage boundary (spatial)	Copper alloy	Air – indoor controlled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-199	3.3-1, 046	B
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor controlled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B
Valve body	Pressure boundary	Carbon steel	Air – indoor controlled (ext)	None	None	VII.J.AP-2	3.3-1, 121	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3-1, 045	B
Valve body	Pressure boundary	Copper alloy	Air – indoor controlled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-199	3.3-1, 046	B
Valve body	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A

Table 3.3.2-10: Essential Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Air – indoor controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	B

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant Specific Notes

1. The Open Cycle Cooling Water (B.2.3.11) AMP is used to manage loss of material for the interior surfaces of the heat exchangers exposed to raw water.

Table 3.3.2-11: Treated Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Piping	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Piping	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-270	3.3-1, 088	A
Piping	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.G.A-650	3.3-1, 198	C

Table 3.3.2-11: Treated Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Piping	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Piping	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping	Leakage boundary (spatial)	Copper alloy	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-271	3.3-1, 093	A
Piping	Leakage boundary (spatial)	Copper alloy	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.G.A-650	3.3-1, 198	C
Piping	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A

Table 3.3.2-11: Treated Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.G.A-650	3.3-1, 198	C
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.G.A-650	3.3-1, 198	C
Steel components	Leakage boundary (spatial)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Strainer	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C2.AP-209b	3.3-1, 004	A
Strainer	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Strainer	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.G.A-650	3.3-1, 198	C

Table 3.3.2-11: Treated Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank (control room water heater)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Tank (control room water heater)	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-270	3.3-1, 088	C
Valve body	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Valve body	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-270	3.3-1, 088	A
Valve body	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3-1, 193	A
Valve body	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-281	3.3-1, 091	A
Valve body	Leakage boundary (spatial)	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C2.AP-209b	3.3-1, 004	A

Table 3.3.2-11: Treated Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	CASS	Treated water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.G.A-650	3.3-1, 198	C
Valve body	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Leakage boundary (spatial)	Copper alloy	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-271	3.3-1, 093	A
Valve body	Leakage boundary (spatial)	Copper alloy	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	Copper alloy	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-272	3.3-1, 095	A
Valve body	Leakage boundary (spatial)	Copper alloy	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C2.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.G.A-650	3.3-1, 198	C

Table 3.3.2-11: Treated Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.E5.AP-278	3.3-1, 095	A
Valve body	Leakage boundary (spatial)	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is enhanced to manage the wall thinning due to erosion aging effect.

Table 3.3.2-12: Circulating Water System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Piping	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Piping	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Pump casing	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-12: Circulating Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump casing	Leakage boundary (spatial)	Gray cast iron	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3-1, 072	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A
Valve body	Leakage boundary (spatial)	Carbon steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Leakage boundary (spatial)	Gray cast iron	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-727	3.3-1, 134	A

Table 3.3.2-12: Circulating Water System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3-1, 072	A
Valve body	Leakage boundary (spatial)	Gray cast iron	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is enhanced to manage the wall thinning due to erosion aging effect.

Table 3.3.2-13: Containment Hydrogen Detectors and Recombiner – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.AP-209c	3.3-1, 004	A

Table 3.3.2-13: Containment Hydrogen Detectors and Recombiner – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.AP-221c	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.AP-209c	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.AP-221c	3.3-1, 006	A
Steel components	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-13: Containment Hydrogen Detectors and Recombiner – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.AP-221c	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.AP-209c	3.3-1, 004	A

Table 3.3.2-13: Containment Hydrogen Detectors and Recombiner – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.F3.AP-221c	3.3-1, 006	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.3.2-14: Plant Sampling – Summary of Aging Management Evaluation

Table 3.3.2-14: Plant Sampling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Instrument	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-48	3.3-1, 117	A
Instrument	Leakage boundary (spatial)	Glass	Treated water (int)	None	None	VII.J.AP-51	3.3-1, 117	A
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Instrument	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A

Table 3.3.2-14: Plant Sampling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Instrument	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Instrument	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-87	3.4-1, 085	B A
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Orifice	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Piping	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.A-103	3.3-1, 124	B A

Table 3.3.2-14: Plant Sampling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-87	3.4-1, 085	B A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-88	3.4-1, 011	B A
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	A
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A

Table 3.3.2-14: Plant Sampling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.A-103	3.3-1, 124	B A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-87	3.4-1, 085	B A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-88	3.4-1, 011	B A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-761c	3.3-1, 232	A
Steel components	Leakage boundary (spatial)	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Strainer	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Strainer	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Strainer	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-87	3.4-1, 085	B A

Table 3.3.2-14: Plant Sampling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank (SGBD sample sparging and chemical addition)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Tank (SGBD sample sparging and chemical addition)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-751c	3.3-1, 222	A
Tank (SGBD sample sparging and chemical addition)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-162	3.4-1, 083	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.AP-79	3.3-1, 125	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E1.A-103	3.3-1, 124	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-87	3.4-1, 085	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-88	3.4-1, 011	B A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.3.2-15: Plant Air – Summary of Aging Management Evaluation

Table 3.3.2-15: Plant Air – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Accumulator	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Accumulator	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-209b	3.3-1, 004	A
Instrument	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-221b	3.3-1, 006	A
Instrument	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Piping	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-15: Plant Air – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Piping	Pressure boundary	Copper alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-209b	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-221b	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Piping and piping components	Structural integrity (attached)	Aluminum	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping and piping components	Structural integrity (attached)	Aluminum	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.A-451b	3.3-1, 189	A
Piping and piping components	Structural integrity (attached)	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.A-763b	3.3-1, 234	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-15: Plant Air – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Piping and piping components	Structural integrity (attached)	Copper alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping and piping components	Structural integrity (attached)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping and piping components	Structural integrity (attached)	Copper alloy	Gas (int)	None	None	VII.J.AP-9	3.3-1, 114	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-209b	3.3-1, 004	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Steel components	Pressure boundary	Carbon steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.A-79	3.3-1, 009	A
Tank (PORV nitrogen backup)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-15: Plant Air – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (PORV nitrogen backup)	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Tank (purge supply/exhaust fan boot seal)	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Tank (purge supply/exhaust fan boot seal)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3-1, 078	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Valve body	Pressure boundary	Copper alloy	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-15: Plant Air – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VII.I.AP-66	3.3-1, 009	A
Valve body	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-209b	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.D.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.D.AP-221c	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None

3.4. AGING MANAGEMENT OF STEAM AND POWER CONVERSION SYSTEMS

3.4.1. Introduction

This Section provides the results of the AMR for those components identified in Section 2.3.4, Steam and Power Conversion Systems, as being subject to AMR. The systems or portions of systems that are addressed in this Section are described in the indicated sections.

- Main and Auxiliary Steam (2.3.4.1)
- Feedwater and Condensate (2.3.4.2)
- Auxiliary Feedwater (2.3.4.3)

3.4.2. Results

The following tables summarize the results of the AMR for the Steam and Power Conversion Systems:

Table 3.4.2-1, Main and Auxiliary Steam - Summary of Aging Management Evaluation

Table 3.4.2-2, Feedwater and Condensate - Summary of Aging Management Evaluation

Table 3.4.2-3, Auxiliary Feedwater - Summary of Aging Management Evaluation

3.4.2.1. Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.4.2.1.1 Main and Auxiliary Steam

Materials

The materials of construction for the main and auxiliary steam system components are:

- Carbon steel
- Copper alloy
- Glass
- Gray cast iron
- Low-alloy steel
- Stainless steel
- Steel

Environments

The main and auxiliary steam system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Steam
- Treated water
- Treated water >140°F

Aging Effects Requiring Management

The following aging effects associated with the main and auxiliary steam system require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Wall thinning – erosion
- Wall thinning – FAC

Aging Management Programs

The following AMPs manage the aging effects for the main and auxiliary steam system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.8)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.4.2.1.2 Feedwater and Condensate

Materials

The materials of construction for the feedwater and condensate system components are:

- Carbon steel
- CASS
- Glass
- Gray cast iron
- Low-alloy steel
- Stainless steel
- Steel

Environments

The feedwater and condensate system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated water
- Treated water >140°F

Aging Effects Requiring Management

The following aging effects associated with the feedwater and condensate system require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Wall thinning – erosion
- Wall thinning – FAC

Aging Management Programs

The following AMPs manage the aging effects for the feedwater and condensate system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.8)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.4.2.1.3 Auxiliary Feedwater

Materials

The materials of construction for the auxiliary feedwater system components are:

- Aluminum
- Carbon steel
- Coating
- CASS
- Copper alloy >15% Zn
- Gray cast iron
- Stainless steel
- Steel

Environments

The auxiliary feedwater system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Gas
- Lubricating oil
- Raw water
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the auxiliary feedwater system require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload

- Reduction in heat transfer
- Wall thinning – erosion

Aging Management Programs

The following AMPs manage the aging effects for the auxiliary feedwater system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Lubricating Oil Analysis (B.2.3.26)
- One-Time Inspection (B.2.3.20)
- Open-Cycle Cooling Water (B.2.3.11)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.4.2.2. AMR Results for Which Further Evaluation is Recommended by the GALL Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Steam and Power Conversion Systems, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

3.4.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in SRP-SLR Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses." For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Cumulative fatigue damage of Steam and Power Conversion Systems components, as described in SRP-SLR Item 3.4.2.2.1, is addressed as a TLAA in Section 4.3.3, Metal Fatigue of Non-Class 1 Components.

3.4.2.2.2 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to stress corrosion cracking (SCC) could occur in indoor or outdoor stainless steel (SS) piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific operating experience (OE) and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the SLRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is occurring, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of *operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.*

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

Steam and Power Conversion Systems contain stainless steel piping, piping components, heat exchangers, and tanks are exposed to uncontrolled indoor air. A review of PBN OE confirms that halides are potentially present in the indoor air environment at PBN. Additionally, insulated piping and components located indoors, particularly those in standby or periodically operated systems, could conservatively see an accumulation of contaminants from water intrusion through or beneath insulation. As such, all stainless steel components exposed to uncontrolled indoor air in the Steam and Power Conversion Systems are susceptible to cracking due to SCC and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, cracking of these components will be managed via the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP for components exposed to air externally. The exception to this is bolting, which is managed by the Bolting Integrity (B.2.3.9) AMP. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) AMP is not used as there are no coating/linings on stainless steel components in the Steam Power and Conversion System. The External Surfaces Monitoring of Mechanical Components (B.2.3.23), and Bolting Integrity (B.2.3.9) AMPs are described in Sections B.2.3.23 and B.2.3.9, respectively. There are no stainless steel components exposed to an underground environment in the Steam and Power Conversion Systems.

3.4.2.2.3 <u>Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys</u>

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing *can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain, and changing weather conditions can result in moisture intrusion into the insulation.*

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, “One-Time Inspection,” describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) GALL-SLR Report AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” for tanks; (b) GALL-SLR Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, “Buried and Underground Piping and Tanks,” for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the “detection of aging effects” program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, “Internal Coatings/Linings for In-Scope

Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

Steam and Power Conversion Systems contain stainless steel piping, piping components, and heat exchangers are exposed to uncontrolled indoor air. A review of PBN OE confirms the potential presence of halides in the indoor environment at PBN. Additionally, insulated piping and components located indoors, particularly those in standby or periodically operated systems, could conservatively see an accumulation of contaminants from water intrusion through or beneath insulation. As such, all stainless steel components exposed to uncontrolled indoor air in the Steam and Power Conversion Systems are susceptible to loss of material due to pitting and crevice corrosion and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, loss of material in these components will be managed via the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP for components exposed to air externally. The exception to this is bolting, which is managed by the Bolting Integrity (B.2.3.9) AMP. These AMPs provide for the management of aging effects through periodic visual inspection. Any visual evidence of loss of material will be evaluated for acceptability. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) AMP is not used as there are no integrity barrier coatings on stainless steel components in the Steam Power and Conversion System. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) and Bolting Integrity (B.2.3.9) AMPs are described in Sections B.2.3.23 and B.2.3.9 respectively. There are no stainless steel components exposed to an underground environment in the steam and power conversion systems.

3.4.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in Branch Technical Position (BTP) IQMB-1 (Appendix A.2, of this SRP-SLR).

Quality Assurance provisions applicable to SLR are discussed in Section B.1.3.

3.4.2.2.5 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs."

The Operating Experience process and acceptance criteria are described in Section B.1.4.

3.4.2.2.6 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant-specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is *applicable if the search of plant specific OE reveals repetitive occurrences. The criteria for recurrence is (a) a 10 year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5 year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).*

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: (i) alternative examination methods (e.g., volumetric versus external visual); (ii) augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and (iii) additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10 year search of plant-specific OE, two instances of a 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

A review of PBN OE identified no corrosion issues that meet the criteria of 'recurring internal corrosion' for raw water, waste water, closed-cycle cooling water, and treated water. Therefore, recurring internal corrosion is not an applicable aging effect for the Steam and Power Conversion Systems. As such, credited PBN AMPs, such as Inspection of Internal Surfaces in Miscellaneous Piping and Ducting

Components (B.2.3.25), do not require augmentation due to recurring internal corrosion.

3.4.2.2.7 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of SLR, acceptance criteria for this further evaluation is being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

Susceptible Material: If the material is not susceptible to SCC, then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines whether the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

Aggressive Environment: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and *underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.*

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Steam and Power Systems contain aluminum piping and piping components exposed to uncontrolled indoor air. A review of PBN OE confirms halides are potentially present in the indoor environment at PBN. As such, all aluminum components exposed to uncontrolled indoor air in the Steam and Power Systems are susceptible to cracking due to SCC and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, cracking of these components will be managed by the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMPs for components exposed to air externally. This AMP provides for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is described in Section B.2.3.23.

3.4.2.2.8 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

The carbon steel condensate storage tank bottoms sit on a concrete pad. However, the concrete meets the ACI 318 requirements, there is no OE indicating degradation of the concrete that could lead to penetration of water to the metal surface, and the tank is not exposed to groundwater. Additionally, the CSTs are located indoors and protected from weather. Therefore, loss of material and cracking of steel or stainless steel exposed to concrete is not an applicable aging effect. Additionally, the condensate storage tanks are not included within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks AMP due to their location indoors and their volume which is less than 100,000 gallons.

3.4.2.2.9 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping *and piping components; (iii) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.*

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

Steam and Power Systems contain aluminum piping and piping components exposed to uncontrolled indoor air. A review of PBN OE confirms halides are potentially present in the indoor environment at PBN. As such, all aluminum components exposed to uncontrolled indoor air in the Steam and Power Systems are susceptible to loss of material and require management via an appropriate program.

Consistent with the recommendation of GALL-SLR, loss of material of these components will be managed by the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMPs for components exposed to air externally. This AMP provides for the management of aging effects through periodic visual inspection. Any visual evidence of loss of material will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is described in Section B.2.3.23.

3.4.2.3. Time-Limited Aging Analysis

The TLAAs identified below are associated with the Steam and Power Conversion Systems components:

- Section 4.3, Metal Fatigue

3.4.3. <u>Conclusion</u>

Steam and Power Conversion Systems piping, fittings, and components that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4. The AMPs selected to manage aging effects for Steam and Power

Conversion Systems components are identified in the summaries in Section 3.4.2 above.

A description of these AMPs is provided in Appendix B along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with Steam and Power Conversion Systems components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the CLB during the SPEO.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 001	Steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3, "Metal Fatigue"	Yes (SRP-SLR Section 3.4.2.2.1)	Cumulative fatigue damage is an aging effect assessed by a fatigue TLAA. Further evaluation is documented in Section 3.4.2.2.1.
3.4-1, 002	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage cracking of stainless steel piping, piping components, and piping elements exposed to air. Further evaluation is documented in Section 3.4.2.2.2.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 003	Stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material of stainless steel piping and piping components, exposed to air externally. Further evaluation is documented in Section 3.4.2.2.3.
3.4-1, 004	Steel external surfaces exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Consistent with NUREG-2191. The Boric Acid Corrosion (B.2.3.4) AMP is used to manage loss of material of steel surfaces exposed to air with borated water leakage.
3.4-1, 005	Steel piping, piping components exposed to steam, treated water	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion (B.2.3.8) AMP is used to manage steel piping, piping components, and heat exchanger shells and channel heads exposed to steam or treated water.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 006	Metallic closure bolting exposed to any environment, soil, underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage loss of preload of metallic closure bolting in an indoor uncontrolled air environment.
3.4-1, 007	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, "Bolting Integrity"	No	Not applicable. There are no high-strength steel closure bolting in the Steam and Power Conversion Systems. Cracking of stainless steel bolting is addressed by line item 3.4-1, 073.
3.4-1, 009	Steel, stainless steel, nickel alloy closure bolting exposed to air- indoor uncontrolled, air-outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage loss of material of stainless steel and steel closure bolting exposed to condensation or uncontrolled air environments.
3.4-1, 011	Stainless steel piping, piping components, tanks, heat exchanger components exposed to steam, treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP-XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage cracking of stainless steel piping, piping components, and heat exchanger components exposed to steam or treated water >60°C (>140°F).

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 012	Steel tanks exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage the steel tanks which are exposed to steam and treated water.
3.4-1, 014	Steel piping, piping components exposed to steam, treated water	Loss of material due to general, pitting, crevice corrosion, MIC (treated water only)	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. This line item has also been applied to gray cast iron and heat exchanger shells and channel heads. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage steel, low-alloy steel, and gray cast iron piping and piping components, heat exchanger shells and channel heads, and the turbine housing exposed to steam or treated water.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 015	Steel heat exchanger components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage steel heat exchanger components exposed to steam or treated water.
3.4-1, 016	Copper alloy, aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC (copper alloy only)	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of copper alloy piping components exposed to treated water.
3.4-1, 018	Copper alloy, stainless steel heat exchanger tubes exposed to treated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage reduction of heat transfer in stainless steel heat exchanger tubes exposed to treated water.
3.4-1, 019	Stainless steel, steel heat exchanger components exposed to raw water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no stainless steel or steel heat exchanger components exposed to raw water in the Steam and Power Conversion Systems within the scope of the GL 89-13 program.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 020	Copper alloy, stainless steel piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not used. Line item 3.4-1, 089 is used for stainless steel piping or piping components exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 022	Stainless steel, copper alloy, steel heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no copper alloy, stainless steel, or steel heat exchanger tubes exposed to raw water in the Steam and Power Conversion Systems within the scope of the GL 89-13 program.
3.4-1, 023	Stainless steel piping, piping components exposed to closed- cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no stainless steel piping, piping components exposed to closed- cycle cooling water >60°C (>140°F) in the Steam and Power Conversion Systems.
3.4-1, 025	Steel heat exchanger components exposed to closed- cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not used. While there are steel heat exchanger components exposed to treated water, these items are addressed under the line item 3.4-1, 015 and managed using the Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 026	Stainless steel heat exchanger components, piping, piping components exposed to closed- cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. While there are stainless steel heat exchanger components exposed to closed-cycle cooling water, these items are addressed under the line item 3.3-1, 049 and managed using the Water Chemistry and One-Time Inspection AMPs.
3.4-1, 027	Copper alloy piping, piping components exposed to closed- cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no copper alloy piping or piping components exposed to closed-cycle cooling water in the Steam and Power Conversion Systems.
3.4-1, 028	Steel, stainless steel, copper alloy heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no stainless steel heat exchanger components, piping, and piping components that have a heat transfer intended function exposed to closed- cycle cooling water in the Steam and Power Conversion Systems.
3.4-1, 030	Steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the steam and power conversion systems

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 032	Gray cast iron, ductile iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no gray cast iron or ductile iron piping or piping components exposed to soil in the Steam and Power Conversion Systems.
3.4-1, 033	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components exposed to treated water, raw water, closed-cycle cooling water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Consistent with NUREG-2191 for material, environment, aging effect, and AMP, but this item is also applied to tanks and heat exchanger components. The Selective Leaching (B.2.3.21) AMP is used to manage loss of material of gray cast iron piping, piping components, heat exchanger components, and tanks exposed to treated water.
3.4-1, 034	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. This item is also applied to gray cast iron. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage the loss of material in steel and gray cast iron surfaces exposed to air.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 035	Aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage the loss of material in aluminum piping components exposed to air. Further evaluation is documented in Section 3.4.2.2.9.
3.4-1, 036	Steel piping, piping components exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel piping or piping components that have an internal environment of outdoor air in the Steam and Power Conversion Systems.
3.4-1, 037	Steel piping, piping components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. The steel piping or piping components that may be exposed to condensation internally are considered to have an air – indoor uncontrolled environment and are addressed by other line items.
3.4-1, 038	Steel piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no components within the scope of the GL 89-13 program in the steam and power conversion systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 040	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not used. There are no steel piping or piping components exposed to lubricating oil in the Steam and Power Conversion System.
3.4-1, 041	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.26) and One-Time Inspection (B.2.3.20) AMPs are used to manage the loss of material in steel heat exchanger components exposed to lubricating oil.
3.4-1, 042	Aluminum piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no aluminum piping or piping components exposed to lubricating oil in the Steam and Power Conversion Systems.
3.4-1, 043	Copper alloy piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no copper alloy heat piping or piping components exposed to lubricating oil in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 044	Stainless steel piping, piping components, heat exchanger components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.26) and One-Time Inspection (B.2.3.20) AMPs are used to manage the loss of material in stainless steel piping, piping components, and heat exchanger components exposed to lubricating oil.
3.4-1, 045	Aluminum heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no aluminum heat exchanger tubes in the Steam and Power Conversion Systems.
3.4-1, 046	Stainless steel, steel, copper alloy heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.26) and One-Time Inspection (B.2.3.20) AMPs are used to manage reduction of heat transfer in steel or stainless steel heat exchanger tubes exposed to lubricating oil.
3.4-1, 047	Stainless steel piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no stainless steel piping, piping components, tanks, or closure bolting exposed to soil or concrete in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 048	Nickel alloy piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no nickel alloy components in the Steam and Power Conversion Systems.
3.4-1, 050	Steel piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no components in the Steam and Power Conversion Systems underground or exposed to soil or concrete within the scope of the Buried and Underground Piping and Tanks (B.2.3.27) AMP. Steel exposed to concrete is covered under a different line item (3.4-1, 051).
3.4-1, 051	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Consistent with NUREG-2191. The steel condensate storage tanks exposed to concrete do not have any aging effects that require management. Further evaluation is documented in Section 3.4.2.2.8.
3.4-1, 052	Aluminum piping, piping components exposed to gas	None	None	No	Not applicable. There are no aluminum components exposed to gas in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 053	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. There are no copper alloy (>8% Al) piping or piping components exposed to air with borated water leakage in the Steam and Power Conversion Systems.
3.4-1, 054	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191. Copper alloy piping and piping components exposed to air do not have any aging effects that require management.
3.4-1, 055	Glass piping elements exposed to lubricating oil, air, condensation, raw water, treated water, air with borated water leakage, gas, closed-cycle cooling water	None	None	No	Consistent with NUREG-2191. Glass piping components exposed to air or treated water do not have any aging effects that require management.
3.4-1, 056	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. There are no nickel alloy components in the Steam and Power Conversion Systems.
3.4-1, 057	PVC piping, piping components exposed to air – indoor uncontrolled, condensation	None	None	No	Not applicable. There are no PVC components in the Steam and Power Conversion Systems.
3.4-1, 058	Stainless steel piping, piping components exposed to gas	None	None	No	Consistent with NUREG-2191. Stainless steel piping components exposed to gas do not have any aging effects that require management.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 059	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191. Steel piping components exposed to gas do not have any aging effects that require management
3.4-1, 060	Metallic piping, piping components exposed to steam, treated water	Wall thinning due to erosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191 for metallic piping and piping components. This line item is also used for managing wall thinning due to erosion in tanks and heat exchanger shells and channel heads. The Flow-Accelerated Corrosion (B.2.3.8) AMP is used to manage wall thinning due to erosion in metallic piping, piping components, and heat exchanger shells and channel heads exposed to steam and treated water.
3.4-1, 061	Metallic piping, piping components, tanks exposed to raw water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.4.2.2.6)	Not used. There are no components exposed to waste water or raw water susceptible to recurring internal corrosion in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 062	Steel, stainless steel or aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no steel tanks exposed to treated water within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP.
3.4-1, 063	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. This line item is also applied to gray cast iron. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage insulated steel, low-alloy steel, and gray cast iron tanks, piping, and piping components exposed to air.
3.4-1, 064	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. Thermal insulation does not have any applicable aging effects for mechanical components beyond jacket integrity. Insulation jacketing is addressed as a commodity in item 3.5-1, 100.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 066	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed- cycle cooling water, raw water, treated water, lubricating oil	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) AMP is used to manage loss of coating or lining integrity for the internally coated condensate storage tanks.
3.4-1, 067	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed- cycle cooling water, raw water, treated water, lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks is not used to manage loss of material for the internally coated condensate storage tanks
3.4-1, 068	Gray cast iron, ductile iron piping, piping components with internal coatings/linings exposed to closed- cycle cooling water, raw water, treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. There are no gray cast iron or ductile iron piping or piping components with internal coatings in the Steam and Power Conversion Systems.
3.4-1, 070	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to lubricating oil, treated water, treated borated water, raw water, waste water	Loss of material due to general (steel; copper alloy in raw water, waste water only), pitting, crevice corrosion, MIC (raw water, waste water environments only)	AMP XI.M18, "Bolting Integrity"	No	Not applicable. There are no closure bolting in the Steam and Power Conversion Systems exposed to lubricating oil, treated water, treated borated water, raw water, waste water.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 072	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no stainless steel or aluminum components exposed to soil or concrete in the Steam and Power Conversion Systems.
3.4-1, 073	Stainless steel closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.9) AMP is used to manage cracking of stainless steel bolting exposed to air.
3.4-1, 074	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Not applicable. There are no underground stainless steel piping, piping components, or tanks included in the Steam and Power Conversion Systems.
3.4-1, 075	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no heat exchanger tubes exposed to air or condensation in the Steam and Power Conversion Systems.
3.4-1, 077	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no elastomer components in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 078	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no elastomer components in the Steam and Power Conversion Systems.
3.4-1, 081	Steel components exposed to treated water, raw water	Long-term loss of material due to general corrosion	AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage long-term loss of material in steel components exposed to raw water. Long-term loss of material is not applicable for treated water systems material because corrosion inhibitors are used.
3.4-1, 082	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Not applicable. There are no stainless steel components exposed to concrete in the Steam and Power Conversion Systems.
3.4-1, 083	Stainless steel, nickel alloy tanks exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel tanks exposed to treated water in the Plant Sampling system or steam in the Heating Steam system.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 084	Stainless steel, nickel alloy piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel piping and piping components.
3.4-1, 085	Stainless steel, nickel alloy piping, piping components, PWR heat exchanger components exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material in stainless steel piping, piping components, and heat exchanger tubes, channel heads, and tubesheets exposed to treated water.
3.4-1, 086	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes internal to components exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no heat exchanger tubes exposed to air or condensation internally in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 089	Steel, stainless steel, copper alloy piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage loss of material and flow blockage due to fouling in steel, stainless steel, and CASS piping and piping components exposed to raw water.
3.4-1, 090	Steel, stainless steel, copper alloy heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage reduction of heat transfer in gray cast iron heat exchanger tubes exposed to raw water.
3.4-1, 091	Steel, stainless steel, copper alloy heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage reduction of heat transfer in gray cast iron heat exchanger tubes exposed to raw water.
3.4-1, 092	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no copper piping or piping components exposed to soil in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 094	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum underground piping, piping components, or tanks in the Steam and Power Conversion Systems.
3.4-1, 095	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Not applicable. There are no underground stainless steel or nickel alloy piping, piping components, or tanks in the Steam and Power Conversion Systems.
3.4-1, 096	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no aluminum tanks in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 097	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum tanks in the Steam and Power Conversion Systems.
3.4-1, 098	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Not used. The stainless steel tanks associated with Steam & Power Conversion are not located outdoors and capacity is less than the threshold (100,000 gallon) for inclusion in the scope of the AMP.
3.4-1, 099	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no stainless steel tanks exposed to soil or concrete in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 100	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Not used. The stainless steel tanks associated with Steam & Power Conversion are not located outdoors and capacity is less than the threshold (100,000 gallon) for inclusion in the scope of the AMP.
3.4-1, 101	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no stainless steel tanks exposed to soil or concrete in the Steam and Power Conversion Systems.
3.4-1, 102	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no aluminum tanks in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 103	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material of stainless steel piping, piping components, and heat exchanger channel heads exposed to air externally. Further evaluation is documented in Section 3.4.2.2.3.
3.4-1, 104	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage cracking of insulated stainless steel piping, piping components, and piping elements exposed to air. Further evaluation is documented in Section 3.4.2.2.2.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 105	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no insulated aluminum components in the Steam and Power Conversion Systems.
3.4-1, 106	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to air, condensation	Cracking due to SCC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. This item is also used for heat exchanger components. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage cracking of copper alloy piping, piping components, piping elements, and heat exchanger components exposed to air.
3.4-1, 107	Copper alloy (>15% Zn or >8% Al) tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no copper alloy tanks in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 109	Aluminum piping, piping components, tanks exposed to air, condensation, raw water, waste water	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.7)	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage cracking of aluminum piping components exposed to air.
3.4-1, 112	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no aluminum underground piping, piping components, or tanks in the Steam and Power Conversion Systems.
3.4-1, 114	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no titanium components in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 115	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not applicable. There are no titanium components in the Steam and Power Conversion Systems.
3.4-1, 116	Titanium heat exchanger tubes exposed to closed- cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no titanium components in the Steam and Power Conversion Systems.
3.4-1, 117	Aluminum piping, piping components, tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.
3.4-1, 119	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no insulated aluminum components in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 120	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum components exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no elastomer components in the Steam and Power Conversion Systems.
3.4-1, 123	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no elastomer components in the Steam and Power Conversion Systems.
3.4-1, 124	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. There are no PVC components in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 125	PVC piping, piping components, tanks exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no PVC components in the Steam and Power Conversion Systems.
3.4-1, 126	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed- cycle cooling water	None	None	No	Not applicable. There are no titanium components in the Steam and Power Conversion Systems.
3.4-1, 127	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. There are no aluminum components in the Steam and Power Conversion Systems.
3.4-1, 128	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. There are no copper components exposed to concrete in the Power and Steam Conversion Systems.
3.4-1, 129	Copper alloy piping, piping components exposed to soil, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no copper components exposed to soil or underground in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 130	Titanium piping, piping components, heat exchanger components other than tubes exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no titanium components in the Steam and Power Conversion Systems.
3.4-1, 131	Copper alloy (>15% Zn) piping, piping components exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Not applicable. There are no copper alloy >15% Zn piping components exposed to air with borated water leakage in the steam and power conversion systems.
3.4-1, 132	Stainless steel piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not used. The environment and material combination do exist. However, this SLRA does not list combinations that have no aging effects unless there is only one environment applicable to that component type and material.
3.4-1, 133	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no aluminum components exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 134	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no titanium components in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 135	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no polymeric components in the Steam and Power Conversion Systems.

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VIII.H.S-02	3.4-1, 009	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VIII.H.SP-142	3.4-1, 006	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VIII.H.S-421	3.4-1, 073	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VIII.H.S-02	3.4-1, 009	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VIII.H.SP-142	3.4-1, 006	A
Drain trap	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Drain trap	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A
Drain trap	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-118b	3.4-1, 002	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Drain trap	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-127b	3.4-1, 003	A
Drain trap	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-87	3.4-1, 085	B A
Filter housing	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Filter housing	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A
Flow element	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Flow element	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A
Flow element	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-71	3.4-1, 014	B A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element	Pressure boundary	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Flow element	Pressure boundary	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-15	3.4-1, 005	A
Flow element	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-98	3.4-1, 011	B A
Flow element	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-155	3.4-1, 084	B A
Flow element	Pressure boundary	Stainless steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Flow element	Throttle	Stainless steel	Steam (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-98	3.4-1, 011	B A
Flow element	Throttle	Stainless steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-155	3.4-1, 084	B A
Flow element	Throttle	Stainless steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Flow element (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Flow element (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A
Heat exchanger (blowdown channel head)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-118b	3.4-1, 002	C
Heat exchanger (blowdown channel head)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-127b	3.4-1, 003	C
Heat exchanger (blowdown channel head)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-80	3.4-1, 085	B A
Heat exchanger (blowdown channel head)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	C

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (blowdown channel head)	Leakage boundary (spatial)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-85	3.4-1, 011	B A
Heat exchanger (blowdown evaporator vent condenser channel head)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-80	3.4-1, 085	B A
Heat exchanger (blowdown evaporator vent condenser channel head)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	C
Heat exchanger (blowdown evaporator vent condenser channel head)	Leakage boundary (spatial)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-85	3.4-1, 011	B A
Heat exchanger (blowdown evaporator vent condenser channel head) (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	C
Heat exchanger (blowdown evaporator vent condenser channel head) (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	C

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (blowdown evaporator vent condenser shell)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4-1, 015	B A
Heat exchanger (blowdown evaporator vent condenser shell)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	C
Heat exchanger (blowdown evaporator vent condenser shell)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.F.S-16	3.4-1, 005	C
Heat exchanger (blowdown evaporator vent condenser shell) (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (blowdown shell)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (blowdown shell)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4-1, 015	B A
Heat exchanger (blowdown shell)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	C
Heat exchanger (blowdown shell)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.F.S-16	3.4-1, 005	C

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (high pressure feedwater heater channel head)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Heat exchanger (high pressure feedwater heater channel head)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	C
Heat exchanger (high pressure feedwater heater channel head)	Leakage boundary (spatial)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-88	3.4-1, 011	B A
Heat exchanger (high pressure feedwater heater channel head) (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	C
Heat exchanger (high pressure feedwater heater channel head) (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	C
Heat exchanger (high pressure feedwater heater shell)	Leakage boundary (spatial)	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.C.SP-71	3.4-1, 014	B A
Heat exchanger (high pressure feedwater heater shell)	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.C.S-408	3.4-1, 060	C

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (high pressure feedwater heater shell)	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.C.S-15	3.4-1, 005	C
Heat exchanger (high pressure feedwater heater shell) (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (low pressure feedwater heater channel head)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Heat exchanger (low pressure feedwater heater channel head)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	C
Heat exchanger (low pressure feedwater heater channel head)	Leakage boundary (spatial)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-88	3.4-1, 011	B A
Heat exchanger (low pressure feedwater heater channel head) (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	C
Heat exchanger (low pressure feedwater heater channel head) (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	C

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (low pressure feedwater heater shell)	Leakage boundary (spatial)	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.C.SP-71	3.4-1, 014	B A
Heat exchanger (low pressure feedwater heater shell)	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.C.S-408	3.4-1, 060	C
Heat exchanger (low pressure feedwater heater shell)	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.C.S-15	3.4-1, 005	C
Heat exchanger (low pressure feedwater heater shell) (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Level element	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Level element	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-74	3.4-1, 014	B A
Level element	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (ext)	None	None	VIII.I.SP-33	3.4-1, 055	A
Level element	Leakage boundary (spatial)	Glass	Treated water (int)	None	None	VIII.I.SP-35	3.4-1, 055	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-98	3.4-1, 011	B A
Orifice	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-155	3.4-1, 084	B A
Orifice	Pressure boundary	Stainless steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Orifice (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Orifice (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A
Piping	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-71	3.4-1, 014	B A
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage boundary (spatial)	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-15	3.4-1, 005	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A
Piping	Leakage boundary (spatial)	Low-alloy steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.S-408	3.4-1, 060	B A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-118b	3.4-1, 002	A
Piping	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-127b	3.4-1, 003	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-87	3.4-1, 085	B A
Piping	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-71	3.4-1, 014	B A
Piping	Pressure boundary	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Piping	Pressure boundary	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-15	3.4-1, 005	A
Piping	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-98	3.4-1, 011	B A
Piping	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-155	3.4-1, 084	B A
Piping	Pressure boundary	Stainless steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Piping (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Piping (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping (insulated)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Piping (insulated)	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VIII.B1.S-08	3.4-1, 001	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VIII.B1.S-08	3.4-1, 001	A
Piping and piping components	Leakage boundary (spatial)	Low-alloy steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VIII.B1.S-11	3.4-1, 001	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Pressure boundary	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VIII.B1.S-08	3.4-1, 001	A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VIII.B1.S-08	3.4-1, 001	A
Piping and piping components	Pressure boundary	Stainless steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Pressure boundary	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VIII.B1.S-08	3.4-1, 001	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-15	3.4-1, 005	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A
Piping and piping components	Structural integrity (attached)	Stainless steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-155	3.4-1, 084	B A
Piping and piping components	Structural integrity (attached)	Stainless steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Piping and piping components (insulated)	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.F.SP-27	3.4-1, 033	A
Pump casing	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A
Rupture disc	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Rupture disc	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A
Steam trap	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.F.SP-27	3.4-1, 033	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Steam trap	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-71	3.4-1, 014	B A
Steam trap	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Steam trap	Leakage boundary (spatial)	Gray cast iron	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-15	3.4-1, 005	A
Steam trap	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-71	3.4-1, 014	B A
Steam trap	Pressure boundary	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Steam trap	Pressure boundary	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-15	3.4-1, 005	A
Steam trap (insulated)	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Steam trap (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Steel components	Leakage boundary (spatial)	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VIII.H.S-30	3.4-1, 004	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steel components	Pressure boundary	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VIII.H.S-30	3.4-1, 004	A
Strainer	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-74	3.4-1, 014	B A
Strainer	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Strainer	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.F.S-16	3.4-1, 005	A
Strainer	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.F.SP-27	3.4-1, 033	A
Strainer	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A
Strainer (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Strainer (insulated)	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tank (blowdown)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4-1, 012	B A
Tank (blowdown)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Tank (blowdown)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.F.S-16	3.4-1, 005	A
Tank (blowdown) (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Valve body	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A
Valve body	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VIII.I.SP-6	3.4-1, 054	A
Valve body	Leakage boundary (spatial)	Copper alloy	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-101	3.4-1, 016	B A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	Stainless steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-155	3.4-1, 084	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Valve body	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-71	3.4-1, 014	B A
Valve body	Pressure boundary	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Valve body	Pressure boundary	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-15	3.4-1, 005	A
Valve body	Pressure boundary	Low-alloy steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-74	3.4-1, 014	B A
Valve body	Pressure boundary	Low-alloy steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-118b	3.4-1, 002	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-127b	3.4-1, 003	A
Valve body	Pressure boundary	Stainless steel	Steam (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-98	3.4-1, 011	B A
Valve body	Pressure boundary	Stainless steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-155	3.4-1, 084	B A
Valve body	Pressure boundary	Stainless steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.B1.S-408	3.4-1, 060	A
Valve body (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Valve body (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A
Valve body (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A

Table 3.4.2-1: Main and Auxiliary Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body (insulated)	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Valve body (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Valve body (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VIII.H.S-02	3.4-1, 009	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VIII.H.SP-142	3.4-1, 006	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VIII.H.S-421	3.4-1, 073	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VIII.H.S-02	3.4-1, 009	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VIII.H.SP-142	3.4-1, 006	A
Flow element	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Flow element	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Flow element	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A
Flow element	Throttle	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Flow element	Throttle	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Flow element	Throttle	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-88	3.4-1, 011	B A

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flow element (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Level element	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Level element	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Level element	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Level element	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A
Level element	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (ext)	None	None	VIII.I.SP-33	3.4-1, 055	A
Level element	Leakage boundary (spatial)	Glass	Treated water (int)	None	None	VIII.I.SP-35	3.4-1, 055	A
Orifice	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Orifice	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Orifice	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Piping	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-88	3.4-1, 011	B A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.SP-118b	3.4-1, 002	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.SP-127b	3.4-1, 003	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Piping	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-88	3.4-1, 011	B A
Piping (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VIII.D1.S-11	3.4-1, 001	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VIII.D1.S-11	3.4-1, 001	A
Piping and piping components	Pressure boundary	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VIII.D1.S-11	3.4-1, 001	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Pump casing	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Pump casing	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Pump casing	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A
Pump casing (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Steam trap	Leakage boundary (spatial)	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Steam trap	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.E.SP-27	3.4-1, 033	A
Steam trap	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Steam trap	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Steam trap	Leakage boundary (spatial)	Gray cast iron	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A
Steel components	Leakage boundary (spatial)	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VIII.H.S-30	3.4-1, 004	A
Steel components	Pressure boundary	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VIII.H.S-30	3.4-1, 004	A
Tank (condensate receiver)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Tank (condensate receiver)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Tank (condensate receiver)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A
Tank (condensate receiver) (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Thermowell	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Thermowell	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Thermowell	Leakage boundary (spatial)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-88	3.4-1, 011	B A
Valve body	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-88	3.4-1, 011	B A

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.E.S-16	3.4-1, 005	A
Valve body	Pressure boundary	CASS	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Valve body	Pressure boundary	CASS	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Valve body	Pressure boundary	CASS	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-88	3.4-1, 011	B A
Valve body	Pressure boundary	Low-alloy steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-74	3.4-1, 014	B A
Valve body	Pressure boundary	Low-alloy steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-87	3.4-1, 085	B A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-408	3.4-1, 060	A

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D1.SP-88	3.4-1, 011	B A
Valve body (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Valve body (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Valve body (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A
Valve body (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Valve body (insulated)	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Valve body (insulated)	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A
Valve body (insulated)	Pressure boundary	Low-alloy steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Valve body (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A

Table 3.4.2-2: Feedwater and Condensate – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Accumulator	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Accumulator	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Accumulator	Pressure boundary	Carbon steel	Gas (int)	None	None	VIII.I.SP-4	3.4-1, 059	A
Accumulator	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Accumulator	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Accumulator	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A
Accumulator	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VIII.H.S-02	3.4-1, 009	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VIII.H.SP-142	3.4-1, 006	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VIII.H.S-421	3.4-1, 073	A
Accumulator	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Accumulator	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Accumulator	Pressure boundary	Carbon steel	Gas (int)	None	None	VIII.I.SP-4	3.4-1, 059	A
Accumulator	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Accumulator	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Accumulator	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A
Accumulator	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VIII.H.S-02	3.4-1, 009	A
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VIII.H.SP-142	3.4-1, 006	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	Bolting Integrity (B.2.3.9)	VIII.H.S-421	3.4-1, 073	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VIII.H.S-02	3.4-1, 009	A
Bolting	Mechanical closure	Stainless steel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VIII.H.SP-142	3.4-1, 006	A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Flow element	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A
Flow element	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A
Heat exchanger (1/2P-29 lube oil cooler channel head)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (1/2P-29 lube oil cooler channel head)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4-1, 015	B A
Heat exchanger (1/2P-29 lube oil cooler shell)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger (1/2P-29 lube oil cooler shell)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VIII.G.SP-76	3.4-1, 041	A
Heat exchanger (1/2P-29 lube oil heat exchanger tubes)	Heat transfer	Stainless steel	Lubricating oil (ext)	Reduction of heat transfer	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VIII.G.SP-102	3.4-1, 046	A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (1/2P-29 lube oil heat exchanger tubes)	Heat transfer	Stainless steel	Treated water (int)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.F.SP-96	3.4-1, 018	B A
Heat exchanger (1/2P-29 lube oil heat exchanger tubes)	Pressure boundary	Stainless steel	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VIII.G.SP-79	3.4-1, 044	A
Heat exchanger (1/2P-29 lube oil heat exchanger tubes)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	D C
Heat exchanger (1/2P-29 lube oil heat exchanger tubesheet)	Pressure boundary	Stainless steel	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VIII.G.SP-79	3.4-1, 044	A
Heat exchanger (1/2P-29 lube oil heat exchanger tubesheet)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	D C
Heat exchanger (P-38A/B bearing cooler channel head)	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Heat exchanger (P-38A/B bearing cooler channel head)	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VIII.G.S-432	3.4-1, 081	A
Heat exchanger (P-38A/B bearing cooler channel head)	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.G.SP-28	3.4-1, 033	C

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (P-38A/B bearing cooler channel head)	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VIII.G.S-438	3.4-1, 091	A
Heat exchanger (P-38A/B bearing cooler channel head)	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (P-38A/B bearing cooler shell)	Pressure boundary	Gray cast iron	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Heat exchanger (P-38A/B bearing cooler shell)	Pressure boundary	Gray cast iron	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VIII.G.SP-76	3.4-1, 041	A
Heat exchanger (P-38A/B bearing cooler tubes)	Heat transfer	Gray cast iron	Lubricating oil (ext)	Reduction of heat transfer	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VIII.G.SP-103	3.4-1, 046	A
Heat exchanger (P-38A/B bearing cooler tubes)	Heat transfer	Gray cast iron	Raw water (int)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VIII.G.S-437	3.4-1, 090	A
Heat exchanger (P-38A/B bearing cooler tubes)	Pressure boundary	Gray cast iron	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VIII.G.SP-76	3.4-1, 041	A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (P-38A/B bearing cooler tubes)	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.G.SP-28	3.4-1, 033	C
Heat exchanger (P-38A/B bearing cooler tubes)	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VIII.G.S-438	3.4-1, 091	A
Heat exchanger (P-38A/B bearing cooler tubes)	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VIII.G.S-432	3.4-1, 081	A
Heat exchanger (P-38A/B bearing cooler tubes)	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (P-38A/B bearing cooler tubesheet)	Pressure boundary	Gray cast iron	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis (B.2.3.26) One-Time Inspection (B.2.3.20)	VIII.G.SP-76	3.4-1, 041	A
Heat exchanger (P-38A/B bearing cooler tubesheet)	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VIII.G.SP-28	3.4-1, 033	C
Heat exchanger (P-38A/B bearing cooler tubesheet)	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VIII.G.S-438	3.4-1, 091	A
Heat exchanger (P-38A/B bearing cooler tubesheet)	Pressure boundary	Gray cast iron	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VIII.G.S-432	3.4-1, 081	A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (P-38A/B bearing cooler tubesheet)	Pressure boundary	Gray cast iron	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Orifice	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Orifice	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Orifice	Pressure boundary	CASS	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A
Orifice	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A
Orifice	Throttle	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Orifice	Throttle	CASS	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A
Orifice	Throttle	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Orifice	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A
Piping	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Piping	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A
Piping	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Piping	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VIII.G.S-432	3.4-1, 081	A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VIII.G.S-436	3.4-1, 089	A
Piping	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Piping	Pressure boundary	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A
Piping	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A
Piping	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VIII.G.S-436	3.4-1, 089	A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A
Piping (insulated)	Leakage boundary (spatial)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Piping (insulated)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A
Piping (insulated)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-402a	3.4-1, 063	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping (insulated)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-16	3.4-1, 005	A
Pump casing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Pump casing	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Pump casing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A
Pump casing	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Steel components	Leakage boundary (spatial)	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VIII.H.S-30	3.4-1, 004	A
Steel components	Pressure boundary	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	VIII.H.S-30	3.4-1, 004	A
Strainer	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Strainer	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A
Strainer	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A
Tank (condensate storage tank)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Tank (condensate storage tank)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	V.A.E-29	3.2-1, 044	A
Tank (condensate storage tank)	Pressure boundary	Carbon steel	Concrete (ext)	None	None	VIII.I.SP-154	3.4-1, 051	A
Tank (condensate storage tank)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-75	3.4-1, 012	B A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (condensate storage tank)	Pressure boundary	Coating	Treated water (int)	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VIII.G.S-401	3.4-1, 066	B
Thermowell	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Thermowell	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A
Turbine casing	Pressure boundary	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.3, Metal Fatigue of Non-Class 1 Components	VIII.G.S-11	3.4-1, 001	A
Turbine casing	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Turbine casing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Valve body	Leakage boundary (spatial)	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Leakage boundary (spatial)	CASS	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A
Valve body	Pressure boundary	Aluminum	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-457c	3.4-1, 109	A
Valve body	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-147b	3.4-1, 035	A
Valve body	Pressure boundary	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VIII.G.S-432	3.4-1, 081	A
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VIII.G.S-436	3.4-1, 089	A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-74	3.4-1, 014	B A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Valve body	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A
Valve body	Pressure boundary	CASS	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VIII.G.S-436	3.4-1, 089	A
Valve body	Pressure boundary	CASS	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	CASS	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A
Valve body	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VIII.G.S-436	3.4-1, 089	A
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-87	3.4-1, 085	B A

Table 3.4.2-3: Auxiliary Feedwater – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-118b	3.4-1, 002	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.G.SP-127b	3.4-1, 003	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

Plant Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.25) AMP is used to manage loss of material and wall thinning due to erosion for the interior surfaces of components exposed to raw water.

3.5. AGING MANAGEMENT OF CONTAINMENTS, STRUCTURES, AND COMPONENT SUPPORTS

3.5.1. Introduction

This section provides the results of the AMR for those components identified in Section 2.4, Scoping and Screening Results: Structures, as being subject to AMR. The structures or structural components that are addressed in this section are described in the indicated sections.

- Containment Structure and Containment internal structural components (2.4.1)
- Circulating Water Pumphouse (2.4.2)
- Control Building (2.4.3)
- Diesel Generator Building (2.4.4)
- Facade (2.4.5)
- Fuel Oil Pumphouse (2.4.6)
- Gas Turbine Building (2.4.7)
- Primary Auxiliary Building (2.4.8)
- Spent Fuel Pool and Transfer Canal (2.4.9)
- Turbine Building (2.4.10)
- Yard Structures (2.4.11)
- 13.8kV Switchgear Building (2.4.12)
- Component Support Commodity (2.4.13)
- Fire Barrier Commodity (2.4.14)
- Cranes, Hoists and Lifting Devices (2.4.15)

3.5.2. Results

The following tables summarize the results of the AMR for Containment, Structures and Component Supports:

Table 3.5.2-1, Containment Structure and Containment Internal Structural Components - Summary of Aging Management Evaluation

Table 3.5.2-2, Circulating Water Pumphouse - Summary of Aging Management Evaluation

Table 3.5.2-3, Control Building - Summary of Aging Management Evaluation

Table 3.5.2-4, Diesel Generator Building - Summary of Aging Management Evaluation

Table 3.5.2-5, Façade - Summary of Aging Management Evaluation

Table 3.5.2-6, Fuel Oil Pumphouse - Summary of Aging Management Evaluation

Table 3.5.2-7, Gas Turbine Building - Summary of Aging Management Evaluation

Table 3.5.2-8, Primary Auxiliary Building - Summary of Aging Management Evaluation

Table 3.5.2-9, Spent Fuel Pool and Transfer Canal - Summary of Aging Management Evaluation

Table 3.5.2-10, Turbine Building - Summary of Aging Management Evaluation

Table 3.5.2-11, Yard Structures - Summary of Aging Management Evaluation

Table 3.5.2-12, 13.8kV Switchgear Building - Summary of Aging Management Evaluation

Table 3.5.2-13, Component Support Commodity - Summary of Aging Management Evaluation

Table 3.5.2-14, Fire Barrier Commodity - Summary of Aging Management Evaluation

Table 3.5.2-15, Cranes, Hoists and Lifting Devices - Summary of Aging Management Evaluation

3.5.2.1. Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.5.2.1.1 Containment Structure and Containment Internal Structural Components

Materials

The materials of construction for the Containment structure and internal structural components are:

- Calcium Silicate or Amosite Asbestos with a Silicate Binder (thermal insulation)
- Coatings
- Concrete (reinforced)
- Copper alloy
- Dissimilar metal welds
- Elastomer
- High-strength steel
- Lubrite®
- Stainless steel
- Steel (including galvanized steel)

Environments

The Containment structure and internal structural components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Groundwater/soil

- Soil
- Treated borated water
- Water-flowing

Aging Effects Requiring Management

The following aging effects associated with the Containment structure and internal structural components require management:

- Cracking
- Cumulative fatigue damage
- Increase in porosity and permeability
- Loss of bond
- Loss of coating or lining integrity
- Loss of leak tightness
- Loss of material
- Loss of mechanical function
- Loss of mechanical properties
- Loss of preload
- Loss of prestress
- Loss of sealing
- Loss of strength (also cited as reduction of strength)

Aging Management Programs

The following AMPs manage the aging effects for the Containment structure and internal structural components:

- 10 CFR Part 50, Appendix J (B.2.3.32)
- ASME Section XI, Subsection IWE (B.2.3.29)
- ASME Section XI, Subsection IWF (B.2.3.31)
- ASME Section XI, Subsection IWL (B.2.3.30)
- Boric Acid Corrosion (B.2.3.4)
- One Time Inspection (B.2.3.20)
- Protective Coating Monitoring and Maintenance (B.2.3.36)
- Structures Monitoring (B.2.3.34)
- Water Chemistry (B.2.3.2)

3.5.2.1.2 Circulating Water Pumphouse Structure

Materials

The materials of construction for the circulating water pumphouse structural components are:

- Concrete (reinforced)
- Steel

Environments

The circulating water pumphouse structural components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater/soil
- Soil
- Water - flowing
- Water - flowing or standing

Aging Effect Requiring Management

The following aging effects associated with the circulating water pumphouse structural components require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of strength

Aging Management Programs

The following AMPs manage the aging effects for the circulating water pumphouse structural components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35)
- Fire Protection (B.2.3.15)
- Structures Monitoring (B.2.3.34)

3.5.2.1.3 Control Building Structure

Materials

The materials of construction for the control building structural components are:

- Concrete (reinforced)
- Concrete block
- Elastomer
- Glass

- Steel
- Wood (EDG air intake missile barrier)

Environments

The control building structural components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater/ soil
- Soil
- Water - flowing

Aging Effect Requiring Management

The following aging effects associated with the control building structural components require management:

- Change in material properties (wood due to rot or mildew)
- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following AMPs manage the aging effects for the control building structural components:

- Fire Protection (B.2.3.15)
- Masonry Walls (B.2.3.33)
- Structures Monitoring (B.2.3.34)

3.5.2.1.4 Diesel Generator Building Structure

Materials

The materials of construction for the diesel generator building structural components are:

- Concrete (reinforced)
- Concrete block
- Elastomer
- Steel

Environments

The diesel generator building structural components are exposed to the following environments:

- Air – indoor controlled
- Air – outdoor
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the diesel generator building structural components require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following AMPs manage the aging effects for the diesel generator building structural components:

- Fire Protection (B.2.3.15)
- Masonry Walls (B.2.3.33)
- Structures Monitoring (B.2.3.34)

3.5.2.1.5 Façade (Unit 1 and 2) Structure

Materials

The materials of construction for the Façade structural components are:

- Concrete (reinforced)
- Concrete block
- Steel

Environments

The Façade structural components are exposed to the following environments:

- Air –indoor uncontrolled
- Air – outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Façade structural components require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of strength

Aging Management Programs

The following AMP manages the aging effects for the Façade structural components:

- Fire Protection (B.2.3.15)
- Masonry Walls (B.2.3.33)
- Structures Monitoring (B.2.3.34)

3.5.2.1.6 Fuel Oil Pumphouse Structure

Materials

The materials of construction for the fuel oil pumphouse structural components are:

- Concrete (reinforced)
- Concrete block
- Steel (including galvanized steel)

Environment

The fuel oil pumphouse structural components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the fuel oil pumphouse structural components require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of strength

Aging Management Programs

The following AMP manages the aging effects for the fuel oil pumphouse structural components:

- Fire Protection (B.2.3.15)
- Masonry Walls (B.2.3.33)
- Structures Monitoring (B.2.3.34)

3.5.2.1.7 Gas Turbine Building Structure

Materials

The materials of construction for the gas turbine building structural components are:

- Concrete (reinforced)
- Steel (including galvanized steel)

Environment

The gas turbine building structural components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the gas turbine building structural components require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of strength

Aging Management Programs

The following AMPs manage the aging effects for the gas turbine building components:

- Fire Protection (B.2.3.15)
- Structures Monitoring (B.2.3.34)

3.5.2.1.8 Primary Auxiliary Building Structure

Materials

The materials of construction for the primary auxiliary building structural components are:

- Concrete (reinforced)
- Concrete block
- Elastomer
- Stainless steel
- Steel (including galvanized steel)

Environments

The primary auxiliary building structural components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the primary auxiliary building structural components require management:

- Cracking
- Distortion
- Hardening
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of strength
- Loss of preload
- Loss of sealing
- Shrinkage

Aging Management Programs

The following AMPs manage the aging effects for the primary auxiliary building structural components:

- Boric Acid Corrosion (B.2.3.4)
- Fire Protection (B.2.3.15)
- Masonry Walls (B.2.3.33)
- Structures Monitoring (B.2.3.34)

3.5.2.1.9 Spent Fuel Pool and Transfer Canal

Materials

The materials of construction for the spent fuel pool structural components are:

- Concrete (reinforced)
- Elastomer
- Stainless steel
- Steel (piles, bolting)

Environments

The spent fuel pool structural components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Groundwater/soil
- Soil
- Treated borated water
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the spent fuel pool structural components require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload

- Loss of sealing
- Loss of strength

Aging Management Programs

The following AMPs manage the aging effects for the spent fuel pool structural components:

- Boric Acid Corrosion (B.2.3.4)
- One-Time Inspection (B.2.3.20)
- Structures Monitoring (B.2.3.34)
- Water Chemistry (B.2.3.2)

In addition to these credited AMPs, spent fuel pool/transfer canal water level and leak off is checked periodically.

3.5.2.1.10 Turbine Building (Unit 1 and 2) Structure

Materials

The materials of construction for the turbine building structural components are:

- Concrete (reinforced)
- Concrete block
- Steel (including galvanized steel)

Environment

The turbine building structural components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater/soil
- Soil
- Water-flowing

Aging Effects Requiring Management

The following aging effects associated with the turbine building structural components require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond

- Loss of material
- Loss of preload
- Loss of strength

Aging Management Programs

The following AMPs manage the aging effects for the turbine building structural components:

- Fire Protection (B.2.3.15)
- Masonry Walls (B.2.3.33)
- Structures Monitoring (B.2.3.34)

3.5.2.1.11 Yard Structures

Materials

The materials of construction for yard structure components are:

- Aluminum
- Concrete (reinforced)
- Concrete block
- Earth
- Stainless Steel
- Steel (including galvanized steel and cast iron)
- Styrofoam

Environment

The yard structure components are exposed to the following environments:

- Air – outdoor
- Air with borated water leakage
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the yard structure components require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond

- Loss of form
- Loss of material
- Loss of preload
- Loss of strength

Aging Management Programs

The following AMPs manage the aging effects for the yard structure components:

- Boric Acid Corrosion (B.2.3.4)
- Structures Monitoring (B.2.3.34)
- Masonry Walls (B.2.3.33)
- Fire Protection (B.2.3.15)

3.5.2.1.12 13.8 kV Switchgear Building Structure

Materials

The materials of construction for the 13.8 kV switchgear building structural components are:

- Concrete (reinforced)
- Concrete block
- Steel (including galvanized steel)

Environment

The 13.8 kV switchgear building structural components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the 13.8 kV switchgear building structural components require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material

- Loss of preload
- Loss of strength

Aging Management Programs

The following AMPs manage the aging effects the 13.8 kV switchgear building structural components:

- Masonry Walls (B.2.3.33)
- Structures Monitoring (B.2.3.34)

3.5.2.1.13 Component Support Commodity

Materials

The materials of construction for the component support commodity are:

- Aluminum
- Concrete (reinforced)
- Elastomer
- Grout (including epoxy (adhesive) or resin-based)
- High-strength steel
- Stainless steel
- Steel (including galvanized steel)

Environment

The component support commodity is exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects associated with the component support commodity require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction in concrete anchor capacity
- Reduction or loss of isolation function

Aging Management Programs

The following AMPs manage the aging effects for the component support commodity:

- ASME Section XI, Subsection IWF (B.2.3.31)
- Boric Acid Corrosion (B.2.3.4)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Structures Monitoring (B.2.3.34)

3.5.2.1.14 Fire Barrier Commodity

Materials

The materials of construction for the fire barrier commodity are:

- Calcium silicate board
- Ceramic fiber (including board and mat)
- Cementitious (spray-on fireproofing)
- Elastomer
- Stainless steel
- Steel

Environment

The fire barrier commodity is exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects associated with the fire barrier commodity require management:

- Cracking
- Hardening
- Loss of material
- Loss of strength
- Separation
- Shrinkage

Aging Management Programs

The following AMPs manage the aging effects for the fire barrier commodity:

- Boric Acid Corrosion (B.2.3.4)
- Fire Protection (B.2.3.15)

3.5.2.1.15 Cranes, Hoists, and Lifting Devices

Materials

The materials of construction for the cranes, hoists, and lifting devices are:

- Steel

Environment

The cranes, hoists, and lifting devices are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects associated with the cranes, hoists, and lifting devices require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the cranes, hoists, and lifting devices components:

- Boric Acid Corrosion (B.2.3.4)
- Inspection of Overhead Heavy Load Handling Systems (B.2.3.13)

3.5.2.2. AMR Results for Which Further Evaluation is Recommended by the GALL Report

NUREG-2192 provides the basis for those programs/issues that warrant further evaluation by the reviewer in the SLRA. For the containment and plant structures, structural commodities, and structural system those programs/issues are addressed in the following sections. *Italicized text* is taken directly from NUREG-2192.

3.5.2.2.1 <u>Pressurized Water Reactor and Boiling Water Reactor Containments</u>

3.5.2.2.1.1 Cracking and Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength and Cracking Due to Differential Settlement and Erosion of Porous Concrete Sub-foundations.

Cracking and distortion due to increased stress levels from settlement could occur in PWR and BWR concrete and steel containments. The existing program relies on ASME Code Section XI, Subsection IWL to manage these aging effects. Also, reduction of foundation strength and cracking, due to differential settlement and erosion of porous concrete subfoundations could occur in all types of PWR and BWR containments. The existing program relies on the structures monitoring program to manage these aging effects. However, some plants may rely on a dewatering system to lower the site groundwater level. If the plant's current licensing basis (CLB) credits a dewatering system to control settlement, further evaluation is recommended to verify the continued functionality of the dewatering system during the subsequent period of extended operation.

Cracks, distortion, and increase in component stresses due to settlement of concrete foundations are considered in the Structures Monitoring AMP (B.2.3.34). All structures at PBN are either founded on spread footings, basemats, or basemats with steel foundation piles that are driven to refusal. The PBN containment concrete base slab is reinforced with high strength reinforcing steel and the slab is founded on H-piles driven to the underlying bedrock. Settlement monitoring and structural inspections have indicated no visible evidence of uneven or excessive settlement since construction of the station. Cracking, distortion, and an increase in component stress levels due to settlement are not probable aging effects at PBN. However, the Structures Monitoring AMP (B.2.3.34) monitors for cracks and distortion and contains inspection criteria to verify these aging effects are not developing. Similarly, the ASME Section XI, Subsection IWL AMP (B.2.3.30) monitors for cracks and degradation in accessible concrete containment areas and would inform the Structures Monitoring AMP (B.2.3.34) if settlement is suspected.

Reduction in foundation strength due to erosion of porous concrete subfoundations is not an aging effect requiring management at PBN. PBN's structure foundations are constructed of solid concrete and not the subject porous type. The foundations are not subject to flowing water, other than groundwater, and there is no permanent dewatering system at PBN. That notwithstanding, the Structures Monitoring AMP (B.2.3.34) monitors for settlement and cracking and for SLR, groundwater is considered to be flowing water.

The identification of indications of settlement by the Structures Monitoring AMP (B.2.3.34), as well as the resistance provided by the materials of construction, provide adequate assurance that reductions in foundation strength for any reason will be identified and managed throughout the SPEO.

3.5.2.2.1.2 Reduction of Strength and Modulus Due to Elevated Temperature

Reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR concrete and steel containments. The implementation of 10 CFR 50.55a and ASME Code Section XI, Subsection IWL *would not be able to identify the reduction of strength and modulus of concrete due to elevated temperature. Subsection CC-3440 of ASME Code Section III, Division 2, specifies the concrete temperature limits for normal operation or any other long-term period. Further evaluation is recommended of a plant-specific AMP if any portion of the concrete containment components exceeds specified temperature limits {i.e., general area temperature greater than 66 °C (Celsius) [150 °F (Fahrenheit)] and local area temperature greater than 93 °C (200 °F)}. Higher temperatures may be allowed if tests and/or calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of the SRP-SLR).*

Elevated temperature impacts on concrete were addressed during the initial license renewal. "The staff found that, based on the design of the hot penetration areas, in combination with the resolution of the corrective action associated with concrete that operated at an elevated temperature and continuing monitoring under the Structures Monitoring Program and ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program, any reduction of strength and modulus of elasticity due to elevated temperatures in PWR concrete would be adequately managed".

The issue of concrete temperatures around the (Unit 2) main steam lines above UFSAR allowable temperatures described in NUREG-1839 (pgs 3-275 to 3-278) was addressed through the corrective action program (apart from LR), with concrete temperatures confirmed to be below UFSAR allowable over three cycles. Insulation installed for the (Unit 2) main steam and feedwater lines restored the penetrations to the original design configuration.

For SLR, the operating experience review did not identify a recurrence of concrete temperatures exceeding UFSAR allowable. The PBN UFSAR states in Section 5.1.2.4 that temperature has been measured at the main steam penetrations and found to be less than 200°F and no greater than 200°F at small hot piping penetrations. Lastly, the ASME Section XI, Subsection IWE (B.2.3.29) AMP and ASME Section XI, Subsection IWL (B.2.3.30) AMP provide management of containment wall and penetrations. Therefore, a plant-specific AMP is not required to manage reduction of strength and modulus due to elevated temperatures for containment penetrations associated with main steam and feedwater lines.

3.5.2.2.1.3 Loss of Material Due to General, Pitting, and Crevice Corrosion

1) *Loss of material due to general, pitting, and crevice corrosion could occur in steel elements of inaccessible areas for all types of PWR and BWR containments. The existing program relies on ASME Code Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J AMPs, to manage this aging effect. Further evaluation is recommended of plant-specific programs to manage this aging effect if corrosion is indicated from the IWE examinations. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

2) *Loss of material due to general, pitting, and crevice corrosion could occur in steel torus shell of Mark I containments. The existing program relies on ASME Code Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J, to*

manage this aging effect. If corrosion is significant, recoating of the torus is recommended. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

3) *Loss of material due to general, pitting, and crevice corrosion could occur in steel torus ring girders and downcomers of Mark I containments, downcomers of Mark II containments, and interior surface of suppression chamber shell of Mark III containments. The existing program relies on ASME Code Section XI, Subsection IWE to manage this aging effect. Further evaluation is recommended of plant-specific programs to manage this aging effect if corrosion is significant. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

PBN is a PWR, therefore, torus corrosion in a BWR, items 2) and 3) above, is not applicable. For item 1 above, corrosion in inaccessible areas of the steel liner plate at PBN was addressed as part of the initial license renewal effort. At the time, liner corrosion due to borated water leakage was identified in both units and ASME Code Subsection IWE augmented inspections performed. The bottom containment liner plate (floor) is covered by an eighteen-inch thick concrete floor (and is therefore considered inaccessible). PBN LR commitments #71 and #72 enhanced the ASME Section XI, Subsection IWE and IWL Inservice Inspection Program regarding acceptance criteria for liner thickness, an overall approach which the NRC staff found acceptable in detecting and correcting flaws in the containment liner plates.

Design and construction of the reinforced concrete containment structure at PBN, including that in contact with the containment liner, is in accordance with ACI 318-63. PBN original concrete specifications met the intent of ACI 201.2R-77 “Guide to Durable Concrete” as described in NUREG-1839. Accessible surfaces of concrete structures including the internal structures within containment are inspected for cracking, spalling, or loss of material.

Concrete core drilled access holes were installed inside the containment to monitor the liner plate for any corrosion in areas of concern. Liner plate monitoring through these core holes, on the 8-foot elevation and keyway, of each containment has shown no significant change over a 10-year period. In addition, the liner plate is fabricated with a leak chase channel (LCC) system which covers all welded seams in the liner plate. The LCCs are welded on the inside of the liner plate, except for the dome LCCs, which are welded to the outside of the liner plate. The LCCs are not presently used but are considered an integral part of the liner plate and therefore a part of the leak tight containment pressure boundary.

Furthermore, the acceptance criteria and augmented inspections for the ASME Section XI, Subsection IWE and IWL Inservice Inspection Program have continued. The ASME Section XI, Subsection IWE AMP for SLR is based on the IWE portion of the ASME Section XI, Subsection IWE and IWL Inservice Inspection Program, including the augmented inspections and acceptance criteria to manage this aging effect. The ASME Section XI, Subsection IWE (B.2.3.29) inspects the moisture barrier at the location where the steel liner becomes embedded in concrete. The ASME Section XI, Subsection IWE AMP also includes inspections in accessible areas, such as penetration sleeves/assemblies, and considerations for inaccessible areas if degradation is detected in accessible areas. The PBN Boric Acid Corrosion

AMP (B.2.3.4) minimizes exposure of susceptible materials to borated water by frequent monitoring of the locations where potential leakage could occur and timely cleaning and repair if leakage is detected. Therefore, a plant specific program to manage loss of material for inaccessible areas of steel (liner) components is not required.

3.5.2.2.1.4 Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature.

*Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for PWR prestressed concrete containments and BWR Mark II prestressed concrete containments is a time-*limited *aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in Section 4.5, "Concrete Containment Unbonded Tendon Pre-stress Analysis," and/or Section 4.7 "Other Plant-Specific Time-Limited Aging Analyses," of the SRP-SLR).*

Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for the containment structures is addressed in the Containment Loss of Prestress TLAA and is managed by the Concrete Containment Unbonded Tendon Pre-Stress (B.2.2.3) AMP and the ASME Section XI, Subsection IWL (B.2.3.30) AMP.

3.5.2.2.1.5 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue, cyclical loading, or cyclical displacement of metal liner, metal plates, suppression pool steel shells (including welded joints) and penetrations (including personnel airlock, equipment hatch, control rod drive (CRD) hatch, penetration *sleeves, dissimilar metal welds, and penetration bellows) for all types of PWR and BWR containments and BWR vent header, vent line bellows, and downcomers may be TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed in Section 4.6, "Containment Liner Plates Metal Containments, and Penetrations Fatigue Analysis," and for cases of plant-specific components, in Section 4.7 "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations, the method used is appropriately defined and discussed in the applicable TLAAs.*

Cumulative fatigue damage for the PBN liner and piping (and ventilation) penetrations for the containment structure is addressed in the Containment Liner Plate, Metal Containments, and Penetrations Fatigue TLAA, Section 4.6, for SLR.

However, a fatigue analysis or waiver for non-piping containment penetrations (i.e., equipment hatch, personnel locks, and electrical) could not be located in the existing documentation. As such, cumulative fatigue damage (cyclic loading evidenced as cracking) for non-piping penetrations will be managed for SLR by the ASME Section XI, Subsection IWE (B.2.3.29) AMP and 10 CFR Part 50, Appendix J (B.2.3.32) AMP. Also, cumulative fatigue damage, evidenced as cracking, for high-temperature system penetrations and for the transfer tube penetration assembly are addressed further in Section 3.5.2.2.1.6 below.

3.5.2.2.1.6 Cracking Due to Stress Corrosion Cracking

Stress corrosion cracking (SCC) of stainless steel (SS) penetration sleeves, penetration bellows*, vent line bellows, suppression chamber shell (interior surface), and dissimilar metal welds could occur in PWR and/or BWR containments. The existing program relies on ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, to manage this aging effect. Further evaluation, including consideration of SCC susceptibility and applicable operating experience (OE) related to detection, is recommended of additional appropriate examinations/evaluations implemented to detect this aging effect for these SS components and dissimilar metal welds.*

Cracking due to SCC was also addressed as part of the initial license renewal effort. Typical details for containment piping and fuel transfer penetrations are provided in the UFSAR [Figures 5.1-2, and 5.1-20]. These penetration assemblies (e.g., sleeves, flued heads, or caps), are carbon steel or stainless steel depending on the system. The fuel transfer penetration is also stainless steel. The fuel transfer penetration also includes bellows that function as barriers against leakage of refueling water from either the fuel transfer canal or refueling cavities inside containment. These bellows do not perform containment integrity functions. Provision is made, by use of continuous leak chase channels, for test pressurizing all welds essential to the integrity of the penetration during plant operation. Furthermore, stainless steel penetrations may involve dissimilar metal welds (DMWs) to the carbon steel liner plate or penetration sleeve. Carbon steel is not susceptible to SCC and stainless steel, as well as DMWs, require a high temperature (>140°F) and/or an aggressive chemical environment (e.g. exposure to chlorides, halides) for SCC. Stainless steel process pipe containment penetrations (CPP), some of which have multiple positions and services, include:

- 1(2)CPP-7, 8 – Residual Heat Removal
- 1(2)CPP-9 – Drain from Reactor Coolant Drain Tank
- 1(2)CPP-10 – Letdown
- 1(2)CPP-11, 29 – RCP Seal Water Return
- 1(2)CPP-3 – Cold Leg Injection
- 1(2)CPP-14 – N2 to Pressurizer Relief Tank
- 1(2)CPP-22 – RV Injection
- 1(2)CPP-26 – Charging
- 1(2)CPP-27 – Hot Leg Injection
- 1(2)CPP-28 – Hot Leg Sample
- 1(2)CPP-30 – Spare
- 1(2)CPP-31, 32 – Containment Pressure Transmitters
- 1(2)CPP-34 – Gas Analyzer Sample from Pressurizer Relief Tank
- 1(2)CPP-54, 55 – Containment Spray

- 1(2)CPP-71 – Drain from Containment Sump
- 1(2)CCP-3 – Fuel Transfer

The containment bulk ambient temperature during normal plant operation is less than or equal to 120°F and localized temperatures at penetrations are less than 200°F by design, as clarified in Section 3.5.2.2.1.2 above. Stainless steel penetrations, and any DMWs, associated with high temperature systems are exposed to temperatures >140°F and may be susceptible to SCC. These same stainless-steel penetrations, and any DMWs, are also susceptible to cyclic loading. However, there has been no site OE of cracking of these stainless-steel penetrations, DMWs, or of the fuel transfer penetration.

Therefore, cracking of stainless-steel penetrations, and any DMWs, for containment penetrations associated with high-temperature systems will be managed by the ASME Section XI, Subsection IWE (B.2.3.29) AMP and 10 CFR Part 50, Appendix J (B.2.3.32) AMP. A supplemental one-time inspection of a representative sample of stainless-steel penetrations or DMWs associated with high-temperature stainless steel piping systems will be included as an enhancement to the ASME Section XI, Subsection IWE (B.2.3.29) AMP to provide confirmation that no additional examinations/evaluations are required. Consistent with the guidance of NUREG-2191, a representative sample size of 20 percent of the population at each unit will be inspected. Stainless steel lines penetrating the containment shell normally having high temperatures and normally in operation include: Letdown, Cold Leg Injection, Reactor Vessel Injection, Charging, Hot Leg Injection, and Hot Leg Sample. As a result, two (2) of the stainless-steel penetrations or DMWs associated with high-temperature stainless steel piping systems and the stainless-steel fuel transfer tube will be inspected on each unit (i.e., three (3) supplemental one-time inspections per unit). Additionally, if SCC is detected as a result of the supplemental one-time inspections, additional inspections will be conducted in accordance with the site's corrective action process.

3.5.2.2.1.7 Loss of Material (Scaling Spalling and Cracking Due to Freeze-Thaw)

Loss of material (scaling, spalling) and cracking due to freeze-thaw could occur in inaccessible areas of PWR and BWR concrete containments. Further evaluation is recommended of this aging effect for plants located in moderate to severe weathering conditions.

Freeze-thaw of inaccessible areas of the PBN concrete containment was also addressed as part of the initial license renewal effort. PBN is located in a severe weathering region. Construction of the PBN containments specified air content within the range specified by current revisions of ACI 318 that is 3-5 percent, and includes a water reducing agent (which ensures low water-to-cement ratio). Furthermore, the concrete meets the recommendations of ACI 318-63 as described in UFSAR Sections 5.1 and 5.6.1.7. In addition, the entire PBN containment buildings are protected from the weather by the Façade structures. PBN occasionally experiences freeze-thaw conditions, which could lead to an increased risk of water intrusion into concrete.

However, site OE has not identified concrete degradation due to freeze-thaw in accessible areas. Instances of water intrusion, including groundwater or rainwater, have been identified and tracked/resolved by the Structures Monitoring (B.2.3.34) AMP. As such, consistent with the initial license renewal, the ASME Section XI, Subsection IWL (B.2.3.30) AMP and the Structures Monitoring (B.2.3.34) AMP would detect concrete aging effects. Lastly, the Structures Monitoring AMP (B.2.3.34) will opportunistically confirm the absence of aging effects by examining normally inaccessible structural components, when scheduled maintenance work and planned plant modifications permit access and will evaluate observed aging effects in accessible areas that could be indicative of degradation in inaccessible areas. Therefore, freeze-thaw would be detected during the SPEO should it occur and a plant-specific program is not required.

3.5.2.2.1.8 Cracking Due to Expansion from Reaction with Aggregates

Cracking due to expansion from reaction with aggregates could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. The GALL-SLR Report recommends further evaluation to determine if a plant-specific aging management *program is required to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

Cracking due to expansion from reaction with aggregates was addressed as part of the initial license renewal. During construction, the aggregates were tested for potential reactivity in accordance with ASTM C227 and ASTM C295. Consequently, cracking and expansion due to reaction with aggregates are not probable aging effects and have not been observed at PBN to date. The NRC determined that cracking due to reaction with aggregates would be adequately managed as described in NUREG-1839. OE since 2005 has not identified any evidence of reaction with aggregates at PBN. However, the Structures Monitoring (B.2.3.34) AMP has been refined, based on industry/fleet information, to include visual examination for patterned cracking, darkened crack edges, water ingress and misalignment that would be indicative of reaction with aggregates, such as alkali-silica reaction (ASR), and includes opportunistic inspection of inaccessible concrete locations. As such, a plant specific program is not required to manage this aging effect; rather, inspections and evaluations performed in accordance with the Structures Monitoring (B.2.3.34) AMP will identify the presence of expansion and cracking due to reaction with aggregates.

3.5.2.2.1.9 Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide and Carbonation

Increase in porosity and permeability due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. Further evaluation is recommended if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Cracking, spalling and leaching of calcium hydroxide of concrete was addressed for initial license renewal. Leaching of calcium hydroxide from reinforced concrete becomes significant only if the concrete is exposed to flowing water. Even if reinforced concrete is exposed to flowing water, such leaching is not significant if the concrete is constructed to ensure that it is dense, well cured, has low permeability, and that cracking is well controlled. Cracking is controlled through proper arrangement and distribution of reinforcing bars. All of the above characteristics are assured if the concrete was constructed with the guidance of ACI 201.2R-77, “Guide to Durable Concrete”. PBN concrete specifications met the intent of ACI 201.2R-77 as described in NUREG-1839.

Additionally, the reinforced concrete of the containment structure is not exposed to flowing water under the current renewed licenses. The entire containment structure of the PBN is housed in an enclosure (façade structure) that provides protection from the weather. The NRC found in NUREG-1839 that, based on concrete specifications for the containment, lack of exposure to flowing water, and the protection from weather provided to the containment by the façade structure, cracking, spalling and increases in porosity and permeability due to leaching of calcium hydroxide would be adequately managed. OE since 2005 has not identified any evidence of leaching of calcium hydroxide.

However, the containment foundation is exposed to groundwater, which for SLR is considered to be flowing water, in NUREG-2191 Table IX.D. Groundwater is periodically sampled by the Structures Monitoring (B.2.3.34) AMP. In addition, the Structures Monitoring (B.2.3.34) AMP includes opportunistic inspection of inaccessible concrete surfaces when excavation, for other reasons, permits access. Evidence of calcium hydroxide leaching or carbonation identified by the Structures Monitoring (B.2.3.34) AMP, would be considered for impact to the ASME Section XI, Subsection IWL (B.2.3.30) AMP. Therefore, similar to current renewed licenses, a plant-specific program is not required.

3.5.2.2.2 <u>Safety-Related and Other Structures and Component Supports</u>

3.5.2.2.2.1 Aging Management of Inaccessible Areas

1. *Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Groups 1–3, 5 and 7–9 structures. Further evaluation is recommended of this aging effect for inaccessible areas of these Groups of structures for plants located in moderate to severe weathering conditions.*

2. *Cracking due to expansion and reaction with aggregates could occur in inaccessible concrete areas for Groups 1–5 and 7–9 structures. Further evaluation is recommended of inaccessible areas of these Groups of structures to determine if a plant-specific AMP is required to manage this aging effect.*

3. *Cracking and distortion due to increased stress levels from settlement could occur in below-grade inaccessible concrete areas of structures for all Groups, and reduction in foundation strength, and cracking due to differential settlement and erosion of porous concrete sub foundations could occur in below-grade inaccessible concrete areas of Groups 1–3, 5–9 structures. The existing program relies on*

structure monitoring programs to manage these aging effects. Some plants may rely on a dewatering system to lower the site groundwater level. If the plant's CLB credits a dewatering system, verification is recommended of the continued functionality of the dewatering system during the subsequent period of extended operation. No further evaluation is recommended if this activity is included in the scope of the applicant's structures monitoring program.

4. *Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation could occur in below-grade inaccessible concrete areas of Groups 1–5 and 7–9 structures. Further evaluation is recommended if leaching is observed in accessible areas that impact intended functions.*

Inaccessible areas at PBN are evaluated as follows:

1. The contract-specified air contents for plant structures were within the range specified by ACI 318-63, and the contract-specified water-to-cement ratio meets the recommendations of ACI 318-63, as described in the UFSAR. PBN occasionally experiences freeze-thaw conditions, which could lead to an increased risk of water intrusion into concrete. However, site OE has not identified concrete degradation due to freeze-thaw in accessible areas. Instances of water intrusion, including groundwater or rainwater, have been identified and tracked/resolved by the Structures Monitoring Program. Therefore, while loss of material and cracking of concrete due to freeze-thaw are not probable, groups 1, 3, 5, 7, and 8 structures at PBN are located in a "severe" weathering region per Figure 1 of ASTM C33, Location of Weathering Regions. As such, consistent with the initial license renewal, the Structures Monitoring (B.2.3.34) AMP would detect concrete aging effects related to freeze-thaw, should it occur. Lastly, the Structures Monitoring (B.2.3.34) AMP opportunistically confirms the absence of aging effects by examining normally inaccessible structural components, when scheduled maintenance work and planned plant modifications permit access and evaluates any observed aging effects in accessible areas that could be indicative of degradation in inaccessible areas.

2. Groups 1, 3, and 5 to 8 structures at PBN are designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. The concrete mix uses Portland cement conforming to ASTM C-150-65. Also, the cement contains no more than 0.60 percent by weight of total alkalis which prevents harmful expansion due to alkali aggregate reaction. Concrete aggregates conform to the requirements of ASTM C-33-67 (fine and coarse aggregate) and conform to the requirements of ASTM C33, "Standard Specification of Concrete Aggregates." Water used for mixing concrete or processing concrete aggregates is free from any injurious amounts of acid, alkali, salts, oil, sediment and organic matter. During construction, the aggregates were tested for potential reactivity to ensure that cracking and expansion due to reaction with aggregates are not probable aging effects at PBN. As

described in NUREG-1839, the NRC determined that cracking due to reaction with aggregates would be adequately managed in the period of extended operation. OE since 2005 has not identified any evidence of reaction with aggregates at PBN. Additionally, the Structures Monitoring (B.2.3.34) AMP has been refined, based on industry/fleet information, to include visual examination for patterned cracking, darkened crack edges, water ingress and misalignment that would be indicative of reaction with aggregates, such as ASR, and includes opportunistic inspection of below-grade inaccessible concrete areas for PBN Groups 1, 3-5, 7, and 8 structures. As such, a plant specific program is not required to manage this aging effect; rather, cracking due to reaction with aggregates in inaccessible areas will be managed by the Structures Monitoring (B.2.3.34) AMP.

3. All Group 1 to 3, and 6 to 8 structures at PBN are either founded on spread footings, or basemats, with the Group 5 spent fuel pool founded on a basemats with steel piles that are driven to refusal. Settlement monitoring and structural inspections indicate no visible evidence of uneven or excessive settlement since construction of the station. Cracking, distortion, and an increase in component stress levels due to settlement are not probable aging effects at PBN and have not been observed to date.

   Reduction in foundation strength due to erosion of porous concrete sub-foundations is not an aging effect requiring management at PBN. PBN's structure foundations are constructed of solid concrete and not the subject porous type. The foundations are not subject to flowing water, other than groundwater, and there is no permanent dewatering system at PBN as described in NUREG-1839 (pgs 3-289, 290). That notwithstanding, the Structures Monitoring (B.2.3.34) AMP monitors for settlement and cracking and for SLR, groundwater is considered to be flowing water. Therefore, the identification of indications of settlement is included in the Structures Monitoring (B.2.3.34) AMP for Groups 1, 3, and 5 to 8 structures and no further evaluation is necessary.

4. Groups 1, 3-5, 7, and 8 structures at PBN are designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. The type and size of aggregate, slump, cement and additives have been established to produce durable concrete in accordance with ACI. Cracking is controlled through proper arrangement and distribution of reinforcing steel. Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R. Change in material properties due to leaching of calcium hydroxide is not a probable aging effect at Point Beach and has not been observed to date. Operating experience has shown that concrete has not experienced unanticipated aging effects at Point Beach.

   That notwithstanding, the foundations of PBN group 1, 3, and 5 to 8 plant structures are considered to be exposed to groundwater, which for SLR is considered to be flowing water, and exterior concrete is exposed to precipitation. Groundwater is periodically sampled by the Structures Monitoring (B.2.3.34) AMP. In addition, the Structures Monitoring (B.2.3.34) AMP includes opportunistic inspection of inaccessible concrete surfaces, when excavation for other reasons permits access, and evaluation of impact to inaccessible area intended functions if degradation, such as leaching or carbonation, is observed in accessible areas.

3.5.2.2.2.2 Reduction of Strength and Modulus Due to Elevated Temperature

Reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR Group 1–5 concrete structures. For any concrete elements that exceed specified temperature limits, further evaluations are recommended. Appendix A of American Concrete Institute (ACI) 349-85 specifies the concrete temperature limits for normal operation or any other long-term period. The temperatures shall not exceed 66 °C (150 °F) except for local areas, which are allowed to have increased temperatures not to exceed 93 °C (200°F). Further evaluation is recommended of a plant-specific program if any portion of the safety- related and other concrete structures exceeds specified temperature limits [i.e., general area temperature greater than 66 °C (150°F) and local area temperature greater than 93 °C (200 °F)]. Higher temperatures may be allowed if tests and/or calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Reduction of strength and modulus of elasticity due to elevated temperatures of Class 1 structures was evaluated for the current renewed PBN licenses and is addressed in NUREG-1839 (pgs 3-291 and 292). For plant areas of concern, temperatures are normally maintained below the specified limits. The focus of the evaluation and response to RAI 3.5-3 discussed in NUREG-1839 was on the main steam and feedwater containment penetrations that had experienced elevated temperatures. This evaluation, including other, smaller high-temperature containment penetrations, is described relative to Section 3.5.2.2.1.2. In addition, other high temperature lines penetrating containment are addressed in the UFSAR (pg. 5.1-48) relative to confirming concrete temperatures are below the specified limits.

In-scope non-containment concrete PBN structures penetrated by piping containing fluids that could have process temperatures above 200ºF include the primary auxiliary building, turbine building and infrequently the control building and diesel generator building during monthly diesel test runs (exhaust and starting air). Piping that could operate above 200ºF and pass through concrete in non-containment penetrations include reactor coolant, residual heat removal, chemical and volume control, sampling, main steam and turbine, feedwater, blowdown, auxiliary steam, condensate, and feedwater heater drains and vents. Process piping carrying hot fluid (pipe temperature greater than 200ºF) routed through penetrations in the non-containment concrete walls by design do not result in temperatures exceeding 200ºF locally or result in “hot spot” on the concrete surface. The piping penetration for systems described above contain pipe sleeves and are designed such that air flow around the penetration would prevent overheating of the concrete. In addition, operating experience has not identified elevated concrete temperatures for non-containment areas. However, analyses to show that concrete temperatures around non-containment hot (> 200ºF) piping would remain below 200ºF could not be located. Rather, insulation on the process piping is conservatively included within the scope of subsequent license renewal to assist in maintaining local primary auxiliary building and turbine building concrete temperatures. The management of this insulation is provided by the External Surfaces of Mechanical Components (B.2.3.23) AMP. As such, a plant-specific program is not required.

3.5.2.2.2.3 Aging Management of Inaccessible Areas for Group 6 Structures

Further evaluation is recommended for inaccessible areas of certain Group 6 structure/aging effect combinations as identified below, whether or not they are covered by inspections in accordance with the GALL-SLR Report, AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," or Federal Energy Regulatory Commission (FERC)/U.S. Army Corp of Engineers dam inspection and maintenance procedures.

1. *Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures. Further evaluation is recommended of this aging effect for inaccessible areas for plants located in moderate to severe weathering conditions.*

2. *Cracking due to expansion and reaction with aggregates could occur in inaccessible concrete areas of Group 6 structures. Further evaluation is recommended to determine if a plant-specific AMP is required to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

3. *Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of Group 6 structures. Further evaluation is recommended if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

PBN Circulating Water Pumphouse (including Forebay) are evaluated as follows:

1. The Groups 6 structures at PBN subject to air-outdoor environment are exposed to temperatures of 32ºF or less of sufficient durations that could cause freeze-thaw aging effects to occur. PBN is located in a "Severe" weathering region per Figure 1 of ASTM C33, Location of Weathering Regions. Section 2.5.2 of the UFSAR addresses lake levels and flooding. It also indicates that beach structures for power stations represent a massive installation and the history of such structures has shown no major damage from ice shoves even where these have been located next to the shoreline on shallow beaches. The outer wall of the forebay is considered adequate to withstand any pressure from ice formation in the lake. The structure below the waterline is considered accessible and periodically inspected. Site operating experience has not identified circulating water

pumphouse or forebay concrete degradation due to freeze-thaw in accessible areas. Loss of material and cracking due to freeze-thaw are aging effects requiring management for the below-grade inaccessible concrete areas of PBN Groups 6 structures and will be managed by the Structures Monitoring (B.2.3.34) AMP. The Structures Monitoring (B.2.3.34) AMP opportunistically confirms the absence of aging effects by examining normally inaccessible structural components in groundwater/soil environment, when scheduled maintenance work and planned plant modifications permit access and coordinates with Inspections of Water- Control Structures Associated with Nuclear Power Plants (B.2.3.35) AMP to evaluate any observed aging effects in accessible areas that could be indicative of degradation in inaccessible areas.

2. The Groups 6 structures at PBN, forebay and circulating water pumphouse, are designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. Concrete aggregates conform to the requirements of ASTM C-33-67 (fine and coarse aggregate) and conform to the requirements of ASTM C33, "Standard Specification of Concrete Aggregates." Water used for mixing concrete or processing concrete aggregates is free from any injurious amounts of acid, alkali, salts, oil, sediment and organic matter. Materials for concrete used in PBN concrete structures and components were specifically investigated, tested, and examined in accordance with pertinent ASTM standards at the time of construction. Furthermore, site operating experience has not identified circulating water pumphouse or forebay concrete cracking in accessible areas. However, based on industry/fleet operating experience cracking due to expansion and reaction with aggregates is an applicable aging effect in below-grade inaccessible concrete areas for Group 6 structures and will be managed by the PBN Inspections of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35) AMP, through the Structures Monitoring (B.2.3.34) AMP.

3. The Groups 6 structures at PBN, forebay and circulating water pumphouse, are designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. The concrete mix uses Portland cement conforming to ASTM C-150-65. However, the below-grade inaccessible concrete areas of Groups 6 concrete structures at PBN are exposed to groundwater which is considered equivalent to a flowing water environment. Therefore, increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation in below-grade inaccessible concrete areas may be an aging effect for the inaccessible concrete of PBN Groups 6 concrete structures, thus, the Inspections of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35) AMP will manage increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation, through the Structures Monitoring (B.2.3.34) AMP, which opportunistically confirms the absence of aging effects by examining normally inaccessible structural components, when scheduled maintenance work and planned plant modifications permit access and coordinates with Inspections of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35) AMP to evaluate any

observed aging effects in accessible areas that could be indicative of degradation in inaccessible areas.

3.5.2.2.2.4 Cracking Due to Stress Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion

Cracking due to SSC and loss of material due to pitting and crevice corrosion could occur in (a) Group 7 and 8 SS tank liners exposed to standing water; and (b) SS and aluminum alloy support members; welds; bolted connections; or support anchorage to building structure exposed to air or condensation (see SRP-SLR Sections 3.2.2.2.2, 3.2.2.2.4, 3.2.2.2.8, and 3.2.2.2.10 for background information).

For Group 7 and 8 SS tank liners exposed to standing water, further evaluation is recommended of plant-specific programs to manage these aging effects. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

For SS and aluminum alloy support members; welds; bolted connections; support anchorage to building structure exposed to air or condensation, the plant-specific OE and condition of the SS and aluminum alloy components are evaluated to determine if the plant-specific air or condensation environments are aggressive enough to result in loss of material or cracking after prolonged exposure. The aging effects of loss of material and cracking in SS and aluminum alloy components is not applicable and does not require management if (a) the plant- specific OE does not reveal a history of pitting or crevice corrosion or cracking and (b) a one-time inspection demonstrates that the aging effects are not occurring or that an aging effect is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA. Visual inspections conducted in accordance with GALL-SLR Report AMP XI.M32, “One-Time Inspection,” are an acceptable method to demonstrate that the aging effects are not occurring at a rate that affects the intended function of the components. One-time inspections are conducted between the 50th and 60th year of operation, as recommended by the “detection of aging effects” program element in AMP XI.M32. If loss of material or cracking has occurred and is sufficient to potentially affect the intended function of SS or aluminum alloy support members; welds; bolted connections; or support anchorage to building structure, either: (a) enhancing the applicable AMP (i.e., GALL-SLR Report AMP XI.S3, “ASME Section XI, Subsection IWF,” or AMP XI.S6, “Structures Monitoring”); (b) conducting a representative sample inspection consistent with GALL-SLR Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components;” or (c) developing a plant-specific AMP are acceptable programs to manage loss of material or cracking (as applicable). Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combinations which are not susceptible to SCC when used in structural support applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. For these alloys and tempers, the susceptibility of cracking due to SCC is not applicable. If these alloys or tempers have been *used, the SLRA states the specific alloy or temper used for the applicable in-scope components.*

Cracking due to SCC and loss of material due to pitting and crevice corrosion is possible in stainless steel and aluminum structural components exposed to any air, condensation, or underground environment where sufficient halides (e.g., chlorides) and moisture are present, and for tank foundation anchor bolts where water may collect. The air environment for stainless steel new fuel storage racks, (refueling cavity) liner, sandbox and ECCS strainer covers, supports or anchorage or aluminum manway covers, fire barrier penetration seals, or insulation jacketing is not expected to be aggressive enough, in rural Wisconsin, to cause cracking or localized loss of material for stainless steel or aluminum exposed to indoor or outdoor air in the presence of wetting.

In addition, stainless steel structural components are limited in number in comparison to the amount of stainless-steel mechanical components. Furthermore, there has been no site operating experience of cracking or localized corrosion of stainless steel or aluminum SSCs. As such, cracking due to SCC and loss of material due to pitting and crevice corrosion is conservatively an applicable aging effect at PBN for stainless steel and aluminum and is managed with the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP, which will interface with the Structures Monitoring (B.2.3.34) AMP, the Fire Protection (B.2.3.15) AMP and the ASME Section XI, Subsection IWE (B.2.3.29) AMP if degradation is detected in the mechanical components.

3.5.2.2.2.5 Cumulative Fatigue Damage Due to Fatigue

Evaluations involving time-dependent fatigue, cyclical loading, or cyclical displacement of component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports are TLAAs as defined in 10 CFR 54.3 only if a CLB fatigue analysis exists. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in Section 4.3, "Metal Fatigue Analysis," and/or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations, the method used is appropriately defined and discussed in the applicable TLAAs.

There is no fatigue analysis for cumulative fatigue damage due to time-dependent fatigue, cyclic loading, or cyclical displacement of component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports at PBN requiring evaluation as a TLAA. Cumulative fatigue damage due to cyclic loading is an applicable aging effect for cranes (overhead heavy load handling systems) at PBN and is addressed in Section 4.7.6.

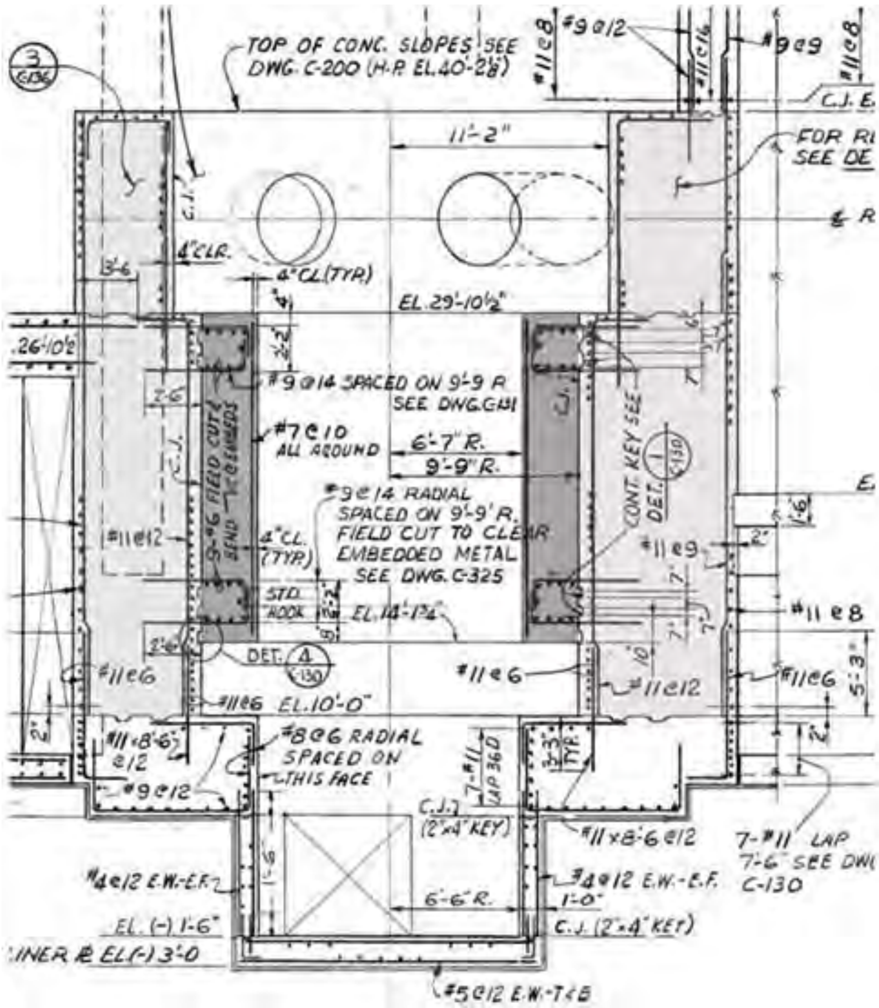
3.5.2.2.2.6 Reduction of Strength and Mechanical Properties of Concrete Due to Irradiation

Reduction of strength, loss of mechanical properties, and cracking due to irradiation could occur in PWR and BWR Group 4 concrete structures that are exposed to high levels of neutron and gamma radiation. These structures include the reactor (primary/biological) shield wall, the sacrificial shield wall, and the reactor vessel support/pedestal structure. Data related to the effects and significance of neutron and gamma radiation on concrete mechanical and physical properties is limited, especially for conditions (dose, temperature, etc.) representative of light-water reactor (LWR) plants. However, based on literature review of existing research, radiation fluence limits of 1 × 10^{19} neutrons/cm2 neutron radiation and 1 × 10^{8} Gy (1 × 10^{10} rad) gamma dose are considered conservative radiation exposure levels beyond which concrete material properties may begin to degrade markedly.

Further evaluation is recommended of a plant-specific program to manage aging effects of irradiation if the estimated (calculated) fluence levels or irradiation dose received by any portion of the concrete from neutron (fluence cutoff energy E > 0.1 MeV) or gamma radiation exceeds the respective threshold level during the subsequent period of extended operation or if plant-specific OE of concrete irradiation degradation exists that may impact intended functions. Higher fluence or dose levels may be allowed in the concrete if tests and/or calculations are provided to evaluate the reduction in strength and/or loss of mechanical properties of concrete from those fluence levels, at or above the operating temperature experienced by the concrete, and the effects are applied to the design calculations. Supporting calculations/analyses, test data, and other technical basis are provided to estimate and evaluate fluence levels and the plant-specific program. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

The reactor vessel (RV) for each unit at PBN is surrounded by a 3 foot 2 inch thick biological shield wall (BSW) which is integral with the 6 foot 6 inch thick primary shield wall (PSW). The BSW surrounds the active fuel region of the RV, where potential radiation damage in the concrete is maximum. The PSW and BSW are shown in Figure 3.5.2.2-1. In this figure, the PSW is shown in a lighter gray shade and the BSW is shown in a darker gray shade. The BSW provides radiation shielding for the PSW and does not perform a structural function. The BSW is attached to the PSW through a cylindrical construction joint at a radius of 9 feet 9 inches from the centerline of the RV. The construction joint contains four layers of radially spaced #9 steel dowels at 14 inches and four continuous concrete shear keys, thus enabling the PSW and BSW to act as a single unit. One quarter inch thick steel liner plates are installed at the inner face of the BSW. The liner plates are welded to each other and are anchored to the concrete with steel angle sections, thus enabling composite action with the concrete wall. Both the Unit 1 and Unit 2 PSWs have the same configuration. Therefore, the following is applicable to both units.

Figure 3.5.2.2-1 – Elevation View of the PSW and BSW



Per Sections 5.1.1.5 and 5.6.1.7 of the UFSAR, the concrete ingredients for the PBN BSW and PSW are as follows in Table 3.5.2.2-1:

Table 3.5.2.2-1
PBN Concrete Specifications

Ingredients	Applicable Specification
Cement	ASTM C-150-65 Type II
Air Entraining Agent	ASTM C-260-66T
Water Reducing Agent	ASTM C-494 Type D (Plastiment)
Aggregate	ASTM C-33 (Fine aggregate is alluvial sand. Coarse aggregate is crushed dolomite.)

Per Section 5.6.1.8 of the PBN UFSAR, the water weight per unit volume is 234 lbs. and the cement weight per unit volume is 4.13 sacks x 94 lbs./sack (388.2 lbs). This results in a water to cement (w/c) ratio of 0.6 for the PBN primary shield wall concrete (with compressive strength of 4000 psi at 90 days).

Neutron fluence and gamma dose calculations were performed by Westinghouse to determine exposures to the BSW, and RV supports (Reference 3.5.4.1). The methodology for the calculations followed the guidance of Regulatory Guide 1.190 (Reference 1.6.25) and was consistent with the NRC approved methodology described in WCAP-18124-NP-A (Reference 3.5.4.2). This methodology has been generically approved for calculations of exposure of the RV beltline (generally, RPV materials opposite the active fuel). No method, generic or specific to PBN has been approved by the NRC for the other calculations performed (i.e., exposure of RV extended beltline materials, RV supports, BSW and PSW concrete).

Westinghouse calculated the maximum neutron fluence (E > 0.1 MeV), gamma dose and displacements per iron atom (dpa) for the end of the SPEO on the BSW, and RV support components based on the reactor models and radiation transport calculations performed for the PBN SLR RV neutron exposure (Section 4.2). These calculations were performed on a fuel-cycle-specific basis at PBN Units 1 and 2 for 72 EFPY, and future projections included a 10 percent positive bias on the peripheral and re-entrant corner assemblies on the projection fuel cycle. Peripheral assemblies have one or more faces exposed to the core baffle plates and re-entrant corner assemblies have one corner exposed the core baffle plates.

Provided in Table 3.5.2.2-2 are the results of the calculations from Westinghouse:

Table 3.5.2.2-2
End of SPEO Exposures for PBN Concrete

Component	Neutron Fluence (n/cm^2)	Gamma Dose (rads)
BSW	5.16×10^{19}	2.35×10^{10}
PSW[1]	$< 1.0 \times 10^{19}$	$< 1 \times 10^{10}$

Note

1. SW fluence exposures were determined using the fluence results for the BSW and RV supports, and gamma dose was determined considering gamma attenuation through the BSW and gamma distribution as a function of active fuel height. Includes the attachment points of the RV supports to the PSW at the ring girder.

Based on the above, only the BSW, which performs no structural function, will experience exposures in excess of the thresholds in NUREG-2192. Although the BSW performs no structural function, it was evaluated for irradiation effects to ensure it will maintain its structural integrity and not affect the PSW under design basis loading conditions.

Neutron fluence and gamma dose attenuation and radiological effects on the BSW were determined utilizing industry guidance provided in EPRI report 3002002676 (Reference 3.5.4.3), PNNL-15870 entitled “Compendium of Material Composition Data for Radiation transport Modeling” (Reference 3.5.4.4), and EPRI Report 3002011710 (Reference 3.5.4.5).

Reference 3.5.4.5 uses attenuation ratio to determine the point into the concrete where the fluence will reach the NUREG-2192 neutron fluence damage threshold of 1 x 10^{19} n/cm^2. The attenuation ratio is defined as (threshold fluence)/(incident fluence at the surface of the concrete). The information in Reference 3.5.4.5 is representative of the PBN concrete in relation to 2-loop PWR fluence model, use of Portland cement, and use of crushed dolomite aggregate. For the PBN BSW, the attenuation ratio was determined to be equal to 1/5.16, which is equal to 0.19. Using the equation in Reference 3.5.4.5, for the neutron fluence attenuation curve, neutron fluence would reach the damage threshold in NUREG-2192 at 3.35 inches into the BSW. However, an additional evaluation was required to address radiation induced volumetric expansion (RIVE) from neutron fluence exposure on the BSW. As a result of the calculated swelling stress in the BSW due to RIVE at the end of the SPEO, the concrete from the inside surface to a depth of 3.92 inches into the BSW would be affected. To account for the RIVE effect, the structural evaluation of the BSW considered the concrete from the inside surface to a depth of 3.92 inches to have zero strength. As an additional conservatism, this zero-strength was applied to the entire vertical surface of the BSW corresponding to the active nuclear fuel region. All liner plates including those covering the top and bottom of the BSW are welded together, resulting in a continuous plate structure supported on concrete with angle sections typically 2 ft apart from each other. The maximum RIVE effect zone of 3.92 inches is applicable only to a limited number of anchors around the mid-height of the BSW. The rest of the anchors remain effective. Consequently, the overall integrity of the BSW liner is not adversely affected by the RIVE effects.

The effects of gamma dose were also determined on the BSW utilizing the information in Reference 3.5.4.5 for attenuation and impact on concrete properties. For the PBN BSW, the gamma dose would fall below the NUREG-2192 concrete irradiation damage threshold for gamma radiation (1.0 x 10^{10} rads) at a depth of 24 inches into the BSW. For the structural evaluation of the BSW, the concrete strength is 0 percent for the first 3.92 inches due to neutron fluence, and 80 percent for an additional 20 inches to account for gamma effects, which is conservative considering the reduction of 20 percent in concrete strength would be at the surface of the BSW, with full concrete strength available at 24 inches. As an additional conservatism, similar to the evaluation of neutron fluence effects, this loss of concrete strength is applied to the entire vertical surface of the BSW corresponding to the active nuclear fuel region.

The design stresses were determined for the concrete section due to the reduced strengths and modulus of elasticity of the irradiated concrete from neutron fluence and gamma dose under the CLB loading. The governing failure mode of the wall is pure tension stress in the wall tangential (horizontal) direction under the combination of accident pressure and thermal load. The tensile capacity of the wall section under pure tension depends only on the area of steel reinforcement and not on the concrete. Therefore, the reduced concrete properties discussed above do not have any impact on the wall section tangential tensile capacity. Comparing with the un-irradiated concrete (where the maximum interaction ratio (IR) was calculated as 0.84, the maximum IR for the irradiated concrete was determined to be 0.89 which has been increased but remains less than 1.0.

The conservatisms in the above evaluation were as follows:

- Exposures were based on 72 EFPY which is more than the actual expected projected EFPY based on a 95% capacity factor of ~69 EFPY.
- Future projections included a 10 percent positive bias on the peripheral and re-entrant corner assemblies on the projection fuel cycle.
- Irradiation effects were assumed to apply to the entire vertical surface of the BSW corresponding to the active fuel region, whereas actual fluence and gamma dose would be much less at the top and bottom regions of the fuel.
- The loss of strength in the BSW concrete as a result of gamma dose incident on the BSW was assumed to apply to the full thickness to the point where the gamma dose falls below the NUREG-2192 damage threshold, when in reality the gamma dose effect would reduce in an approximate linear fashion from the outside surface.
- The latest research data presented in Reference 3.5.4.5 indicates that the threshold for damage to concrete from gamma dose may be higher than 1 x 10^{10} rads.

With regard to the effect of gamma heating, heating from radiation was considered and described in Reference 3.5.4.5. A base case was analyzed with what were considered limiting conditions for thermal conductivity, radiation levels, rebar location, air gap (between the reactor vessel and the primary shield wall inner surface) temperature, air gap flow, and outside wall temperature. For a 150ºF air temperature in the air gap, the calculated maximum temperature in the concrete was 168ºF at a depth of approximately 6 inches from the inside surface of the concrete. The 150ºF air temperature in the air gap for the EPRI report is well above the required <105ºF ambient design temperature for the containment ventilating systems at PBN (Section 5.3.1.1 of the UFSAR). Accordingly, gamma heating is not considered an issue for the PBN BSW and PSW concrete.

Therefore, the BSW and PSW will continue to satisfy the design criteria considering the long-term radiation effects and a plant specific AMP or enhancements to an existing AMP are not required. The BSW and PSW will continue to be inspected as part of the Structures Monitoring (B.2.3.34) AMP.

Furthermore, Group 4 structures that are commodities inside containment are located outside the primary shield wall. As such, Group 4 structures that are commodities will not experience cumulative fluence or gamma irradiation above the thresholds; thus, reduction of strength and mechanical properties of concrete or embrittlement of steel due to irradiation is not an applicable aging effect for the component support or fire barrier commodities or cranes located inside containment.

3.5.2.2.2.7 Expected Further Evaluation for Loss of Fracture Toughness due to Irradiation Embrittlement of Reactor Vessel (RV) Supports from NRC Review of the First Three SLRAs

Loss of fracture toughness due to irradiation embrittlement from accumulated neutron fluence and gamma dose could occur in BWR and PWR structural support components (including associated weldments and bolted connections), located in the vicinity of the Reactor Vessel (RV), made of steel material exposed to low-temperature, low-flux radiation in an air-indoor uncontrolled environment. These components include the RV steel supports, neutron shield tank, steel structural support components of reactor shield wall and sacrificial shield wall, or other steel structural support components located in the vicinity of the RV. The irradiation aging effect could result in reducing or compromising the structural integrity of the above steel structural components. Further evaluation is recommended to determine if a plant-specific aging management program (AMP) or plant-specific enhancements to selected GALL-SLR AMPs is needed to manage the aging effects due to irradiation embrittlement in these steel structural support components located in the vicinity of the RV for the subsequent period of extended operation. Loss of function due to radiation exposure (neutron and/or gamma) of related non-steel (except concrete) components (e.g., Lubrite® or other lubricant/coating in support sliding feet) that may have been used in RV supports and are important to capability to perform its function should also be evaluated and dispositioned, with supporting technical information, on a plant-specific basis for the subsequent period of extended operation. The acceptance criteria for a plant-specific program or program enhancements are described in BTP RLSB-1 (Appendix A.1 of NUREG-2192 (SRP-SLR).

The PBN Units 1 and 2 RV support structure, which is identical for both units, consists of a six-sided structural steel ring girder supported at each apex by ~19 foot long steel columns which pass through the BSW extending downward to the interior concrete structure below the RV. The columns are 12-inch diameter schedule 120 A53 steel pipe. The six columns of the support structure are bolted at the top to the ring girder and pinned at the bottom to the floor anchor. Three of the columns are totally surrounded by the BSW, and the other three are partially surrounded by the BSW. The center of each segment of the ring girder provides lateral and rotational restraint by structural members embedded in the PSW concrete.

The RV has six supports pads, one at each of the four RV primary loop nozzles, and two additional gusset-braced support pads that are welded directly to the RV. Each RV support bears on a support shoe, which is fastened to the support structure. The support shoe is a structural member that transmits the support loads to the supporting structure. It is designed to restrain vertical, lateral, and rotational movement of the RV but to allow for thermal growth by permitting radial sliding on the bearing plates at each support.

Per the PBN UFSAR, the RV supports have been designed to withstand the load combinations of dead, thermal, seismic, and accident loads. For the CLB design loads the considered load combinations are as follows in Table 3.5.2.2-3:

Table 3.5.2.2-3
PBN Design Reactor Vessel Support Loads per Support (kips)

Loading and Load Combination(1)	Vertical (N)	Horizontal (V)
Deadweight	192	0
Thermal	123	0.3
OBE Seismic	110	89
SSE Seismic	160	177
LOCA	153	51
Normal Combination	315	0.3
Upset Combination	425	89.3
Faulted 1 Combination	475	177.3
Faulted 2 Combination	628	228.3

Notes

1. Normal = Deadweight + Thermal
   Upset = Normal + OBE Seismic
   Faulted-1 = Normal + SSE Seismic
   Faulted-2 = Normal + SSE Seismic + LOCA

2. The RCS primary equipment supports are designed and qualified in accordance with the American Institute of Steel Construction (AISC) "Specification for the Design of Structural Steel for Buildings." The load cases, load combinations, and the applicable allowable stress limits are summarized in UFSAR, Table A.5-3, Control Room Building Section, N-S

The RV supports load and load combinations are less than the appropriate allowable load limits, as presented in Table 3.5.2.2-4, Summary of RPV Support Component Stress Interaction Ratios, below.

Table 3.5.2.2-4
Summary of RPV Support Component Stress Interaction Ratios

Support	Component	Controlling Interaction Ratios (<100%)			
		Normal	Upset	Faulted 1	Faulted 2
RV Shoe	Screw Shear	18.19%	29.56%	30.23%	35.05%
	Shoe Net Tension	0.05%	14.22%	14.12%	18.18%
Support Structure	Box Beam	21.54%	29.65%	28.35%	36.01%
	Pipe Column	65.52%	90.03%	66.75%	89.49%

The NRC previously identified radiation embrittlement of the RV supports as a generic safety issue (GSI-15, Reference 1.6.26). The NRC resolved the issue, as documented in NUREG-1509 (Reference 1.6.27) on the basis of a risk-informed evaluation, without imposing new requirements on licensees. The review concluded that loss of fracture toughness due to irradiation embrittlement will not affect the ability of the RV structural steel to perform its component intended functions through the original design life of the plant. However, this review was not performed for an 80-year plant life. Accordingly, a review of the aging effect of reduction in fracture toughness due to embrittlement from exposure to neutron fluence of the PBN reactor vessel support steel was performed for SLR.

As noted in Section 3.5.2.2.2.6, neutron fluence calculations were performed by Westinghouse to determine exposures to the RV supports. The methodology for the calculations followed the guidance of Regulatory Guide 1.190 and was consistent with the NRC approved methodology described in WCAP-18124-NP-A. This methodology has been generically approved for calculations of exposure of the RV beltline (generally, RPV materials opposite the active fuel). No method, generic or specific to PBN has been approved by the NRC for the other calculations performed (i.e., exposure of RV extended beltline materials, RV supports, BSW and PSW concrete).

Westinghouse calculated the maximum neutron fluence (E > 0.1 MeV and displacements per iron atom (dpa) for the end of the SPEO on the RV support components (Reference 3.5.4.6), based on the reactor models and radiation transport calculations performed for the PBN SLR RV neutron exposure (Section 4.2). These calculations were performed on a fuel-cycle-specific basis at PBN Units 1 and 2 for 72 EFPY, and future projections included a 10 percent positive bias on the peripheral and re-entrant corner assemblies on the projection fuel cycle. Peripheral assemblies have one or more faces exposed to the core baffle plates and re-entrant corner assemblies have one corner exposed the core baffle plates.

Maximum projected neutron exposures (E > 0.1 MeV) in terms of fluence and displacements per iron atom of the PBN RV support structures are provided in Table 3.5.2.2-5:

Table 3.5.2.2-5
72 EFPY dpa Exposures and Fluence for PBN RV Support Components

Component	Displacements per Iron Atom (dpa)	Fluence n/cm^2 (E > 0.1 MeV)
Support Column 1 – maximum	5.84E-03	1.48E+19
Support Column 1 – top of support foot	2.70E-05	8.28E+16
Support Column 1 – bottom of column	2.27E-05	6.76E+16
Support Column 2 – maximum	5.69E-04	1.49E+18
Support Column 2 – top of support foot	2.74E-05	8.40E+16
Support Column 2 – bottom of column	2.51E-05	7.49E+16
Ring Girder – inside bottom edge	3.35E-03	9.26E+18
Ring Girder – inside top edge	1.15E-03	3.40E+18
Ring Girder – outside bottom edge	1.14E-03	3.09E+18
Ring Girder – outside top edge	3.43E-04	1.06E+18

Column 2 above is one of three columns totally surrounded by the BSW, and Column 1 is one of three columns partially surrounded by the BSW.

The critical flaw sizes for RV support components were determined by setting the applied stress intensity factor equal to fracture toughness and back-calculating the flaw size. The critical flaw sizes were then compared to the ASME Section XI allowable flaw sizes. This comparison approach is allowable per Section 4.3.4.1 of NUREG-1509. In most cases, the critical flaw sizes are larger than the Section XI allowable flaw sizes by a large margin; thereby concluding that the PBN reactor vessel support components continue to be structurally stable (i.e., flaw tolerant) considering 80 years of radiation or embrittlement effects on the supports. The critical flaw sizes for PBN RV support components at the end of the SPEO (72 EFPY) are presented in Table 3.5.2.2-6 below:

Table 3.5.2.2-6 – Summary of Critical Flaw Sizes for 72 EFPY[(1)]

Loading Condition (see Notes below)	Critical Flaw Size (a/t, flaw depth over thickness)									
	Column (t = 1”)	Box Ring Girder Flange(2) (t = 1.5”)	I-Beam Web (2) (t = 1”)	Shear Brace: Bolt (OD = 1.6012”)	Shear Brace: Shear Key (t = 2”)	Bolts at Box Ring Girder (OD = 1.6012”)	Pin at Bottom of Column (OD = 3.994”)	Support Shoe Box (t = 7.96”)	Leveling Screw (OD =3.54”)	Base Plate (t = 2”)
Normal	59.6 %	2.2 %(3)	3.8 %(3)	99.8 %	99.9 %	16.9 %	3.8 %	65.4 %	16.4 %	80.0 %
Upset	62.9 %	2.4 %(3)	3.4 %(3)	51.5 %	99.5 %	4.8 % (3)	1.8 %	42.2 %	21.3 %	80.0 %
Faulted-1	57.0 %	2.2 %(3)	3.0 %(3)	41.5 %	98.3 %	3.4 % (3)	1.3 %	28.1 %	12.4 %	80.0 %
Faulted-2	44.4 %	1.9 %(3)	2.8 %(3)	37.4 %	97.2 %	2.1 % (3)	0.7 %	21.6 %	9.5 %	80.0 %
Section XI Allowable Flaw Size (a/t)	3.1 %	3.7 %	4.3 %	9.4 %	3.1 %	9.4 %	0.20 %	1.9 %	4.2 %	3.6 %

Notes

1. The critical flaw sizes are determined by setting applied stress intensity factor equal to fracture toughness and back-calculating flaw size.
2. This location considers welding residual stress equal to 110 ksi (yield strength + 10 ksi).
3. These critical flaw sizes are less than the Section XI allowable flaw sizes. See further discussion below.

For the three PBN RV support components with critical flaw sizes less than the Section XI allowable flaw sizes (box ring girder flange, I-beam web and bolts at the box ring girder) the critical flaw sizes would have been discovered and repaired/replaced prior to installation as described below.

For the box ring girder flange and I-beam web, critical flaw sizes were compared against the requirements in AWS D2.0 'Quality of Welds' which notes that no cracks in welds would have been allowed during initial fabrication. The box ring girder and I-beam welds would be free from indications after initial fabrication and after an extended period of time since crack growth mechanisms are not present at the RV supports. Thus, these critical flaw sizes were deemed to be acceptable.

For the box ring girder bolts, the critical flaw size is less than the ASME Section XI allowable flaw size. However, ASTM A-490-76 standards state that bolts with transverse discontinuities (circumferential flaws) are considered defective and would have been replaced prior to use. The bolts at the box ring girder would be free from indications after initial fabrication of the supports and after an extended period of time since crack growth mechanisms are not present at the RV supports. Thus, these critical flaw sizes are deemed to be acceptable.

Based on the discussions above the RV supports at PBN Units 1 and 2 are structurally stable (i.e., flaw tolerant) considering 80 calendar years (72 EFPY) of radiation embrittlement effects. Additionally, there is sufficient level of flaw tolerance demonstrated to justify continuing the current visual examination (VT-3) of the RV structural steel supports as part of the PBN ASME Section XI, Subsection IWF Inservice Inspection (B.2.3.31) Program.

Operating Experience

Section 4.3.1.1 of NUREG-1509 states that physical examination of the RV supports is essential to the evaluation. The purpose of the examination is to detect visible signs of degradation of the supports, including, but not limited to, rust, corrosion, cracks or permanent deformation of the members. Figure 4-2 of NUREG-1509 identifies "evaluate existing physical condition" as one of the key inputs to the "preliminary evaluation". Examinations performed to date on the PBN RV supports as part of the current PBN ASME Section XI, Subsection IWF Inservice Inspection Program consist of VT-3 visual inspections. These inspections are summarized below with the specifics provided on the portal:

Unit 1

VT-3 inspections of accessible portions of the Unit 1 PBN RV supports were performed in 2010. These inspections were performed on all accessible areas to the extent possible. The VT-3 inspection data sheet from the 2010 inspection indicated acceptable results meeting the acceptance criteria of IWF-3410 and did not identify any areas requiring further evaluation.

The acceptance criteria specified in IWF-3410 is as follows:

"(a) Component support conditions which are unacceptable for continued service shall include:

(1) Deformations or structural degradations of fasteners, springs, clamps, or other items;
(2) Missing detached, or loosened support items;
(3) Arc strikes, weld spatter, paint, scoring, roughness, or general corrosion on close tolerance machined or sliding surfaces;
(4) Improper hot or cold settings of spring supports and constant load supports;
(5) Misalignment of supports;
(6) Improper clearances of guides and stops.

(b) Except as noted in IWF-3410(a), the following are examples of non-relevant conditions:

(1) Fabrication marks (e.g., from punching, layout, bending, rolling, and machining);
(2) Chipped or discolored paint;
(3) Weld spatter on other than close tolerance machined or sliding surfaces;
(4) Scratches and surface abrasion marks;
(5) Roughness or general corrosion which does not reduce the load bearing capacity of the support;
(6) General conditions acceptable by the material Design, and/or Construction Specifications.*"*

Unit 2

VT-3 inspections of accessible portions of the Unit 2 PBN RV supports were performed in 2009. These inspections were performed on all accessible areas to the extent possible. The VT-3 inspection data sheet from the 2009 inspection indicated acceptable results meeting the acceptance criteria of IWF-3410 and did not identify any areas requiring further evaluation.

Based on these results, a plant specific AMP or enhancements to an existing AMP are not required to manage loss of fracture toughness due to irradiation embrittlement of the RV supports at PBN.

3.5.2.3. Time-Limited Aging Analysis

The TLAAs identified below are associated with the Containments, Structures and Component Supports components:

- Section 4.5, Concrete Containment Tendon Prestress
- Section 4.6, Containment Liner Plate, Metal Containments, and Penetrations Fatigue
- Section 4.7, Other Plant-Specific Time-Limited Aging Analysis

3.5.3. <u>Conclusion</u>

The structural components and commodities subject to AMR have been identified in accordance with the criteria of 10 CFR 54.4. The AMPs selected to manage the effects of aging on structural components and commodities are identified in

Section 3.5.2 above. A description of the AMPs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the demonstrations provided in Appendix B, the effects of aging associated with the structural components and commodities will be managed such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the SPEO.

3.5.4. References

3.5.4.1. Westinghouse LTR-REA-20-28-NP, Revision 0, “Reactor Vessel, Reactor Vessel Supports, and Concrete Bioshield Exposure Data in Support of the Point Beach Unit 2 Subsequent License Renewal (SLR) Time-Limited Aging Analysis (TLAA)”, July 31, 2020 (Enclosure 4, Attachment 1).

3.5.4.2. Westinghouse Report WCAP-18124-NP-A, Revision 0, “Fluence Determination with RAPTOR-M3G and FERRET,” July 2018.

3.5.4.3. EPRI Report No. 3002002676, “Expected Condition of Reactor Cavity Concrete After 80-Years of Radiation Exposure”, Electric Power Research Institute, Charlotte, NC, March 2014.

3.5.4.4. PNNL 15870, Revision 1 “Compendium of Material Composition Date for Radiation Transport Modelling”, April 2006.

3.5.4.5. EPRI Report No. 3002011710, “Irradiation Damage of the Concrete Biological Shield Wall for Aging Management”, EPRI, Palo Alto, CA, May 2018.

3.5.4.6. WCAP-18554-P/NP, Revision 1, “Fracture Mechanics Assessment of Reactor Pressure Vessel Structural Steel Supports for Point Beach Units 1 and 2”, September 2020 (Enclosure 4, Attachment 2 and Enclosure 5, Attachment 2).

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 001	Concrete: dome; wall; basemat; ring girders; buttresses, concrete elements, all	Cracking and distortion due to increased stress levels from settlement.	AMP XI.S2, "ASME Section XI, Subsection IWL, and/or AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.1.1)	PBN does not rely on a de-watering system to control settlement. However, the Structures Monitoring (B.2.3.34) AMP and the ASME Section XI, Subsection IWL (B.2.3.30) AMP inspections would identify cracking or distortion due to differential settlement of the containment. Further evaluation is documented in Section 3.5.2.2.1.1.
3.5-1, 002	Concrete: foundation; subfoundation	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation	AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.1.1)	Not applicable. PBN does not rely upon a de-watering system to control settlement; and is not constructed of porous concrete. Further evaluation is documented in Section 3.5.2.2.1.1.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 003	Concrete: dome; wall; basemat; ring girders; buttresses, concrete: containment; wall; basemat, concrete: basemat, concrete fill- in annulus	Reduction of strength and modulus of elasticity due to elevated temperature (>150°F general; >200°F local)	Plant-specific AMP or AMP XI.S2 "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.2)	Not required. As described in the UFSAR and consistent with the current renewed licenses, temperatures of containment penetrations are below the allowable general and local temperature thresholds for reduction of strength and modulus by design. This includes thermal insulation of the Main Steam and Feedwater penetrations that experienced elevated temperatures prior to initial license renewal. The high-temperature Main Steam and Feedwater Penetrations are managed by the ASME Section XI, Subsection IWE (B.2.3.29) AMP (penetration assembly) and ASME Section XI, Subsection IWL (B.2.3.30) AMP (concrete). Further evaluation is documented in Section 3.5.2.2.1.2.
3.5-1, 004	This line item only applies to BWRs.				
3.5-1, 005	Steel elements (inaccessible areas): liner; liner anchors; integral attachments, steel elements (inaccessible areas): suppression chamber; drywell; drywell head; embedded shell; region shielded by diaphragm floor (as applicable).	Loss of material due to general pitting corrosion	AMP XI.S1, "ASME Section XI, Subsection IWE" and AMP XI.S4 "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.3)	Consistent with NUREG-2191. Inaccessible areas of the liner plate, liner plate and keyway channel, and liner plate anchors and attachments are managed by the ASME Section XI, Subsection IWE (B.2.3.29) AMP and 10 CFR Part 50 Appendix J (B.2.3.32) AMP. Further evaluation is documented in Section 3.5.2.2.1.3.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 006	This line item only applies to BWRs.				
3.5-1, 007	This line item only applies to BWRs.				
3.5-1, 008	Prestressing system: tendons	Loss of prestress due to relaxation: shrinkage; creep; elevated temperature	TLAA, SRP-SLR Section 4.5, – "Concrete Containment Tendon Prestress" and/or SRP-SLR Section 4.7, " Other Plant-Specific TLAA”	Yes (SRP-SLR Section 3.5.2.2.1.4)	Consistent with NUREG-2191. Concrete containment tendon prestress TLAA is addressed in Section 4.5. Further evaluation is documented in Section 3.5.2.2.1.4.
3.5-1, 009	Metal liner, metal plate, personnel airlock, equipment hatch, control rod drive (CRD) hatch, penetration sleeves; penetration bellows, steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell; unbraced downcomers, steel elements: vent header; downcomers	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR "Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis"	Yes (SRP-SLR Section 3.5.2.2.1.5)	Consistent with NUREG-2191 for liner and most mechanical penetration assemblies. Containment Liner Plate, and Penetrations Fatigue TLAA is addressed in Section 4.7.6. Cyclic loading of Airlocks, Hatches and Electrical Penetration assemblies are addressed for item number 3.5-1, 027. Further evaluation is documented in Section 3.5.2.2.1.5. In addition, cracking (cyclic or SCC) of high-temperature mechanical penetration assemblies that are stainless steel or include dissimilar metal welds is addressed for item number 3.5-1, 010.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 010	Penetration Sleeves Penetration bellows	Cracking due to SCC	AMP XI.S1, “ASME Section XI, Subsection IWE,” and AMP XI.S4, “10 CFR Part 50, Appendix J”	Yes (SRP-SLR Section 3.5.2.2.1.6)	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE (B.2.3.29) AMP and 10 CFR Part 50, Appendix J (B.2.3.32) AMP manage cracking of stainless steel and dissimilar metal weld penetration assemblies exposed to an uncontrolled indoor air environment. Further evaluation is documented in Section 3.5.2.2.1.6.
3.5-1, 011	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze- thaw	Plant-specific AMP or AMP XI.S2 “ASME Section XI, Subsection IWL,” and/or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.7)	Containment structure is located inside the façade building and protected from weather. However, PBN does experience freeze-thaw conditions in the winter. As such, the ASME Section XI, Subsection IWL (B.2.3.30) AMP and Structures Monitoring (B.2.3.34) AMP, which includes opportunistic inspection of inaccessible concrete, would identify any degradation that would allow groundwater to penetrate the containment basemat or adjacent tendon gallery walls. Further evaluation is documented in Section 3.5.2.2.1.7.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 012	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment, concrete fill-in annulus	Cracking due to expansion from reaction with aggregates	Plant-specific AMP or AMP XI.S2 "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.8)	The Structures Monitoring (B.2.3.34) AMP manages cracking for inaccessible concrete with a focus on portions exposed to groundwater/soil environments as leading indicators. Further evaluation is documented in Section 3.5.2.2.1.8.
3.5-1, 013	Item number 3.5-1, 013 is deleted in NUREG-2192.				
3.5-1, 014	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific AMP or AMP XI.S2 "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes (SRP-SLR)	Not required. The PBN containment structure is located entirely inside the façade building and is not susceptible to water-flowing other than groundwater. The Structures Monitoring (B.2.3.34) AMP check of groundwater and opportunistic inspection of inaccessible areas, as well as input to/from the ASME Section XI, Subsection IWL (B.2.3.30) AMP would identify leaching or carbonation of containment basemat or adjacent tendon gallery walls exposed to groundwater (water-flowing). Further evaluation is documented in Section 3.5.2.2.1.9.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 015	Item number 3.5-1, 015 is deleted in NUREG-2192.				
3.5-1, 016	Reinforced concrete containment structure (accessible)	Increase in porosity and permeability Cracking; Loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S2, "ASME Section XI, Subsection IWL" and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWL (B.2.3.30) AMP manages increase in porosity and permeability, cracking, and loss of material (spalling, scaling) for accessible containment concrete exposed to uncontrolled indoor air.
3.5-1, 017	Item number 3.5-1, 017 is deleted in NUREG-2192.				
3.5-1, 018	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze- thaw	AMP XI.S2, "ASME Section XI, Section IWL," and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. Façade structure protects the containment structure from weather. However, freeze-thaw conditions may occur during winter months. The Structures Monitoring (B.2.3.34) AMP manages cracking and loss of material for accessible concrete areas where water could collect.
3.5-1,019	Reinforced concrete containment structure (accessible)	Cracking due to expansion from reaction with aggregates	AMP XI.S2, "ASME Section XI, Subsection IWL" and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWL (B.2.3.30) AMP manages cracking of accessible concrete exposed to an uncontrolled indoor air environment.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 020	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S2, "ASME Section XI, Section IWL"	No	Not applicable. Inside the façade building, the PBN containment structure is not exposed to water-flowing environment in accessible areas.
3.5-1, 021	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses; reinforcing steel	Cracking; loss of bond; loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S2, "ASME Section XI, Subsection IWL" and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWL (B.2.3.30) AMP manages cracking, loss of bond, and loss of material (spalling, scaling) for accessible containment concrete exposed to uncontrolled indoor air.
3.5-1, 022	Item number 3.5-1, 022 is deleted in NUREG-2192.				
3.5-1, 023	Concrete (inaccessible areas): basemat; reinforcing steel, dome; wall	Cracking; loss of bond and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S2, "ASME Section XI, Subsection IWL, and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWL (B.2.3.30) AMP and Structures Monitoring (B.2.3.30) AMP manage cracking, loss of bond, and loss of material (spalling, scaling) for inaccessible concrete exposed to uncontrolled indoor air inside the façade building.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 024	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): dome; wall; basemat	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S2, "ASME Section XI, Subsection IWL , "and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWL (B.2.3.30) AMP supplemented by the Structures Monitoring (B.2.3.34) AMP manage increase in porosity and permeability, cracking, and loss of material (spalling, scaling) in inaccessible concrete areas exposed to uncontrolled indoor air.
3.5-1, 025	Item number 3.5-1, 025 is deleted in NUREG-2192.				
3.5-1, 026	Moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S1, "ASME Section XI, Section IWE"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE (B.2.3.29) AMP manages loss of sealing or other defects for the liner plate (and core hole) moisture barriers exposed to uncontrolled indoor air.
3.5-1, 027	Metal liner, metal plate, airlock, equipment hatch, CRD hatch; penetration sleeves; penetration bellows, steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	AMP XI.S1, "ASME Section XI, Section IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. A fatigue analysis or waiver could not be located for airlock, hatch and electrical penetration assemblies. As such, the ASME Section XI, Subsection IWE (B.2.3.29) AMP and 10 CFR Part 50 Appendix J (B.2.3.32) AMP manage cyclic loading of air lock, hatch, and electrical penetration assemblies. including copper alloy and steel accessories, exposed to uncontrolled indoor air. Mechanical penetration assemblies, including ventilation and fuel transfer tube, are addressed with item number 3.5-1, 009 above.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 028	Personnel airlock, equipment hatch, CRD hatch	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, “ASME Section XI, Subsection IWE” and AMP XI.S4 “10 CFR Part 50, Appendix J”	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE (B.2.3.29) AMP and 10 CFR Part 50, Appendix J (B.2.3.32) AMP manage loss of material of the Containment Structure hatches, air locks and accessories, including copper alloy and steel accessories, exposed to uncontrolled indoor air.
3.5-1, 029	Personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms	Loss of leak tightness due to mechanical wear	AMP XI.S1 "ASME Section XI, Subsection IWE" , and AMP XI.S4, “10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE (B.2.3.29) AMP and 10 CFR Part 50, Appendix J (B.2.3.32) AMP manage loss of leak tightness due to mechanical wear of airlock and hatch accessories exposed to uncontrolled indoor air.
3.5-1, 030	Pressure-retaining bolting	Loss of preload due to self-loosening	AMP XI.S1, "ASME Section XI, Section IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE (B.2.3.29) AMP and 10 CFR Part 50, Appendix J (B.2.3.32) AMP manage loss of preload due to self-loosening of the Containment Structure pressure-retaining bolting exposed to uncontrolled indoor air.
3.5-1, 031	Pressure-retaining bolting, steel elements: downcomer pipes	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, "ASME Section XI, Section IWE"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE (B.2.3.29) AMP manages loss of material of steel exposed to uncontrolled indoor air.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 032	Prestressing system: tendons; anchorage components	Loss of material due to corrosion	AMP XI.S2, "ASME Section XI, Subsection IWL"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWL (B.2.3.30) AMP manages loss of material of the steel tendons and anchorage components associated with the post tensioning system exposed to uncontrolled indoor air.
3.5-1, 033	Seals and gaskets	Loss of sealing due to wear, damage, erosion, tear, surface, cracks, other defects	AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J (B.2.3.32) AMP will be used to manage loss of sealing of seals associated with the Containment Structure seals and gaskets exposed to a uncontrolled indoor air environment.
3.5-1, 034	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage	AMP XI.S8, "Protective Coating Monitoring and Maintenance"	No	Consistent with NUREG-2191. The Protective Coating Monitoring and Maintenance (B.2.3.36) AMP manages loss of coating integrity of the Containment Structure internal Service Level 1 coatings.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 035	Steel elements (accessible areas): liner; liner anchors; integral attachments, penetration sleeves, drywell shell; drywell head; drywell shell in sand pocket regions; suppression chamber; drywell; embedded shell; region shielded by diaphragm floor (as applicable)	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, "ASME Section XI, Section IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.3)	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE (B.2.3.29) AMP and 10 CFR Part 50, Appendix J (B.2.3.32) AMP manage loss of material of accessible steel elements exposed to uncontrolled indoor air. Further evaluation is documented in Section 3.5.2.2.1.3. Inaccessible steel liner elements and attachments are addressed in item number 3.5-1, 005 above.
3.5-1, 036	This line item only applies to BWRs.				
3.5-1, 037	This line item only applies to BWRs.				
3.5-1, 038	This line item only applies to BWRs.				
3.5-1, 039	This line item only applies to BWRs.				
3.5-1, 040	This line item only applies to BWRs.				
3.5-1, 041	This line item only applies to BWRs.				

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 042	Groups 1-3, 5, 7- 9: concrete (inaccessible areas): foundation	Loss of material (spalling, scaling) and cracking due to freeze- thaw	Plant-specific aging management program or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.1)	Group 2 and 9 structures are not applicable to PBN. PBN is located in a severe weathering region, where freezing conditions are occasionally experienced. However, a plant-specific AMP is not required to manage loss of material, cracking in inaccessible areas. Consistent with the current renewed licenses, the Structures Monitoring (B.2.3.34) AMP would detect degradation of concrete due to freeze-thaw, should it occur, and includes opportunistic examination of normally inaccessible components when excavated for other reasons. Further evaluation is documented in Section 3.5.2.2.2.1, item 1.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 043	All Groups except Group 6: concrete (inaccessible areas): all	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.2)	Group 2 and 9 structures are not applicable to PBN. Consistent with the current renewed licenses, a plant-specific AMP is not required to manage cracking in inaccessible areas. The Structures Monitoring (B.2.3.34) AMP includes examination for cracking, darkened crack edges, water ingress and misalignment that would be indicative of reaction with aggregates. The Structures Monitoring (B.2.3.34) AMP also includes opportunistic examination of below-grade inaccessible concrete areas. Further evaluation is documented in Section 3.5.2.2.2.1, item 2.
3.5-1, 044	All Groups: concrete: all	Cracking and distortion due to increased stress levels from settlement	AMP XI.S6, Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.2.1.3)	Group 2 and 9 structures are not applicable to PBN. PBN does not rely upon a de-watering system to control groundwater level and settlement is included in the Structures Monitoring (B.2.3.34) AMP. Further evaluation is documented in Section 3.5.2.2.2.1, item 3.
3.5-1, 045	Item number 3.5-1, 045 is deleted in NUREG-2192.				

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5-1, 046	Groups 1-3, 5-9: concrete: foundation; sub foundation	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete sub foundation	AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.2.1.3)	Not applicable. Group 2 and 9 structures are not applicable to PBN. As described for item 3.5-1, 044, PBN does not rely upon a de-watering system to control groundwater level. In addition, concrete foundations, sub-foundations are not porous. Further evaluation is documented in Section 3.5.2.2.2.1, item 3.
3.5-1, 047	Groups 1-5, 7-9: concrete (inaccessible areas): exterior above- and below- grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation.	Plant-specific aging management program or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.4)	Group 2 and 9 structures are not applicable to PBN. Consistent with the current renewed licenses, a plant-specific AMP is not required for inaccessible areas. For SLR groundwater is considered to be flowing water where leaching or carbonation could potentially occur. The Structures Monitoring (B.2.3.34) AMP includes opportunistic inspection of inaccessible concrete surfaces, when excavated for other reasons, and evaluation of impact to inaccessible area intended functions if degradation, such as leaching or carbonation, is observed in accessible areas. Further evaluation is documented in Section 3.5.2.2.2.1, item 4.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 048	Groups 1-5: concrete: all	Reduction of strength and modulus due to elevated temperature (>150°F general; >200°F local)	Plant-specific aging management program	Yes (SRP-SLR Section 3.5.2.2.2.2)	Not applicable. A plant-specific AMP is not required. Reduction of strength and modulus are not aging effects requiring management at PBN. There have been no instances of elevated temperatures for PBN plant structures other than containment (which is addressed in item 3.5-1, 003 and Section 3.5.2.2.1.2). In addition, insulation for high-temperature piping (> 200°F) is in scope to assist in maintaining local primary auxiliary building and turbine building concrete temperatures and is managed by the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP. Further evaluation is documented in Section 3.5.2.2.2.2.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 049	Group 6 - concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Loss of material (spalling, scaling) and cracking due to freeze- thaw.	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.1)	PBN is located in a severe weathering region. The Circulating Water Pumphouse structure (including Forebay) are occasionally exposed to freezing temperatures. However, a plant specific AMP is not required. There has been no degradation of Circulating Water Pumphouse concrete from freeze-thaw. PBN credits the Structures Monitoring (B.2.3.34) AMP with managing loss of material and cracking in inaccessible locations. Further evaluation is documented in Section 3.5.2.2.2.3, Item 1.
3.5-1, 050	Groups 6: concrete (inaccessible areas): all	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.2)	A plant-specific AMP is not required for the inaccessible areas of the PBN Circulating Water Pumphouse structure. The Structures Monitoring (B.2.3.34) AMP (which includes opportunistic inspection of inaccessible concrete when excavated for other reasons) is credited with managing cracking in inaccessible areas of PBN structures, including the Circulating Water Pumphouse structure. Further evaluation is documented in Section 3.5.2.2.2.3, Item 2.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 051	Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.3)	A plant-specific AMP is not required for the inaccessible areas of the PBN Circulating Water Pumphouse structure. The Structures Monitoring (B.2.3.34) AMP is credited with managing the inaccessible areas of plant structures including the Circulating Water Pumphouse structure. Further evaluation is documented in Section 3.5.2.2.2.3, Item 3.
3.5-1, 052	Groups 7, 8 - steel components: tank liner	Cracking due to SCC; Loss of material due to pitting and crevice corrosion	Plant-specific aging management program	Yes (SRP-SLR Section 3.5.2.2.2.4)	Not applicable. Tanks at PBN are addressed with the mechanical system to which they belong. Furthermore, the External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is credited with managing the condition of stainless-steel components in locations where water could collect (stand). Further evaluation is documented in Section 3.5.2.2.2.4.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 053	Support members; welds; bolted connections; support anchorage to building structure	Cumulative fatigue damage due to cyclic loading (Only if CLB fatigue analysis exists)	TLAA, SRP-SLR Section 4.3 "Metal Fatigue," and/or Section 4.7 "Other Plant-Specific Time-Limited Aging Analyses"	Yes (SRP-SLR Section 3.5.2.2.2.5)	Not applicable. CLB fatigue analysis does not exist for support members, bolted connections; and anchorage to building structure. Crane load cycles, including the support members, welds, hardware and anchorage are addressed in Section 4.7.6 as described in Table 3.5.2-15. Further evaluation is documented in Section 3.5.2.2.2.5.
3.5-1, 054	All groups except 6: concrete (accessible areas): all	Cracking due to expansion from reaction with aggregates	AMP XI.S6 "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing cracking of accessible concrete exposed to uncontrolled indoor air, and outdoor air environments.
3.5-1, 055	Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Reduction in concrete anchor capacity due to local concrete degradation / service induced cracking or other concrete aging mechanisms	AMP XI.S6 "Structures Monitoring"	No	Consistent with NUREG- 2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing reduction in concrete anchor capacity for accessible concrete exposed to uncontrolled indoor air, and outdoor air environments.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5-1, 056	Concrete: exterior above- and below- grade; foundation; interior slab	Loss of material due to abrasion; cavitation	AMP XI.S7, "Inspection of Water- Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35) AMP is credited with managing loss of material and cavitation of accessible concrete exposed to a water – flowing or standing environment.
3.5-1, 057	Constant and variable load spring hangers; guides; stops	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191 with exception. The ASME Section XI, Subsection IWF (B.2.3.31) AMP is credited with managing loss of mechanical function for constrain and variable load supports exposed to an uncontrolled indoor air environment, as described in Table 3.5.2-13.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5-1, 058	Earthen water-control structures: dams; embankments; reservoirs; channels; canals and ponds	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	AMP XI.S7, "Inspection of Water- Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Not applicable. Consistent with the current renewed licenses, earthen water control structures are not credited at PBN. Rip-rap bank topography is described in UFSAR Section 2.5 and Appendix A.7.2 but is not credited for external flooding or wave run-up.
3.5-1, 059	Group 6: concrete (accessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S7, "Inspection of Water- Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35) AMP is credited with managing cracking, loss of bond, and loss of material (spalling, scaling) of accessible Circulating Water Pumphouse concrete exposed to outdoor air.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 060	Group 6: concrete (accessible areas): exterior above- and below-grade; foundation	Loss of material (spalling, scaling) and cracking due to freeze- thaw	AMP XI.S7, "Inspection of Water- Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35) AMP is credited with managing loss of material and cracking, loss of bond of accessible Circulating Water Pumphouse concrete exposed to outdoor air.
3.5-1, 061	Group 6: concrete (accessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S7, "Inspection of Water- Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35) AMP is credited with managing an increase in porosity and permeability and loss of strength for accessible Circulating Water Pumphouse concrete exposed to outdoor air, and water-flowing or standing.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 062	Group 6: Wooden Piles; sheeting	Loss of material; change in material properties due to weathering, chemical degradation, and insect infestation repeated wetting and drying, fungal decay	AMP XI.S7, "Inspection of Water- Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with the current renewed licenses, the Structures Monitoring (B.2.3.34) AMP is credited with managing loss of material and change in material properties for wooden beams of the Emergency Diesel Generator Train A missile barrier outside the Control Building Structure as listed in Table 3.5.2-3. A note E is used. There are no wooden piles or sheathing used in the PBN Circulating Water Pumphouse structure.
3.5-1, 063	Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below- grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing leaching or carbonation of exterior plant structure concrete and foundations where groundwater or precipitation run-off forms a flowing water environment.
3.5-1, 064	Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below- grade; foundation	Loss of material (spalling, scaling) and cracking due to freeze- thaw	AMP XI.S6, "Structures Monitoring	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing loss of material and cracking for accessible plant structure concrete exposed to outdoor air.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5-1, 065	Groups 1-3, 5, 7-9: concrete (inaccessible areas): below-grade exterior; foundation, Groups 1-3, 5, 7-9: concrete (accessible areas): below-grade exterior; foundation, Groups 6: concrete (inaccessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing cracking, loss of bond, loss of material for inaccessible plant structure concrete exposed to groundwater/soil or soil.
3.5-1, 066	Groups 1-5, 7, 9: concrete (accessible areas): interior and above-grade exterior	Cracking, Loss of bond, Loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6 "Structures Monitoring"	No	Consistent with NUREG-2191 The Structures Monitoring (B.2.3.34) AMP is credited with managing cracking, loss of bond, and loss of material for accessible plant structure concrete exposed to uncontrolled indoor air, and outdoor air environments.
3.5-1, 067	Groups 1-5, 7, 9: Concrete: interior; above-grade exterior, Groups 1-3, 5, 7-9 - concrete (inaccessible areas): below-grade exterior; foundation, Group 6: concrete (inaccessible areas): all	Increase in porosity and permeability, Cracking, Loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S6 "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing potential increase in porosity and permeability, cracking, and loss of material due to aggressive chemical attack for inaccessible plant structure concrete in uncontrolled indoor air, outdoor air, and groundwater/soil environments.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 068	High-strength steel structural bolting	Cracking due to SCC	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191 with exception. The ASME Section XI, Subsection IWF (B.2.3.31) AMP is credited with managing cracking for any high strength bolting for ASME Class 1, 2, and 3 supports. Cracking of any high-strength used in non-ASME component supports is managed by the Structures Monitoring (B.2.3.34) AMP.
3.5-1, 069	Item number 3.5-1, 069 is deleted in NUREG-2192.				
3.5-1, 070	Masonry walls: all	Cracking due to restraint shrinkage, creep, aggressive environment	AMP XI.S5, "Masonry Walls"	No	Consistent with NUREG-2191. The Masonry Walls (B.2.3.33) AMP is credited with managing cracking of masonry walls exposed to uncontrolled indoor air and outdoor air.
3.5-1, 071	Masonry walls: all	Loss of material (spalling, scaling) and cracking due to freeze- thaw	AMP XI.S5, "Masonry Walls"	No	Consistent with NUREG-2191. The Masonry Walls (B.2.3.33) AMP is credited with managing cracking of masonry walls due to freeze-thaw.
3.5-1, 072	Seals; gasket; moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing loss of sealing for seals and weatherproofing in the Primary Auxiliary Building and Control Building.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5-1, 073	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage	AMP XI.S8, "Protective Coating Monitoring and Maintenance"	No	Consistent with NUREG-2191. The Protective Coating Monitoring and Maintenance (B.2.3.36) AMP is credited with managing aging effect of Service Level I coatings relative to precluding blockage of the Emergency Core Cooling System (ECCS) sump strainers.
3.5-1, 074	Sliding support bearings; sliding support surfaces	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S6, "Structures Monitoring"	No	Not applicable. There are no sliding support bearings or sliding support surfaces outside of containment. Applicable sliding components addressed under item 3.5-1, 075.
3.5-1, 075	Sliding surfaces	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191 with exception. The ASME Section XI, Subsection IWF (B.2.3.31) AMP is credited with managing aging effect of sliding surfaces exposed to indoor air environment inside Containment.
3.5-1, 076	This line item only applies to BWRs				
3.5-1, 077	Steel components: all structural steel	Loss of material due to corrosion	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing loss of material of structural steel components exposed to uncontrolled indoor air and outdoor air.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5-1, 078	Stainless steel fuel pool liner	Cracking due to SCC; Loss of material due to pitting and crevice corrosion	AMP XI.M2, "Water Chemistry," and monitoring of the spent fuel pool water level and leakage from the leak chase channels	No	Consistent with NUREG-2191 with exception. The Water Chemistry (B.2.3.2) AMP, in conjunction with continued monitoring of spent fuel pool level and leak chase channel checks, is credited with managing cracking and loss of material of the stainless-steel spent fuel pool liner (gate and passive upender) exposed to treated borated water.
3.5-1, 079	Steel components: piles	Loss of material due to corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing loss of material of steel piles for the spent fuel pool, as well as for the containments.
3.5-1, 080	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing loss of material for structural bolting exposed to uncontrolled indoor air. Item 3.5-1, 082 addresses structural bolting located outdoors.
3.5-1, 081	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Not used. Consistent with NUREG-2191, bolted connections for ASME Class 1, 2, and 3 component supports are addressed with Item 3.5-1, 091.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 082	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing loss of material for structural bolting exposed to outdoor air. Item 3.5-1, 080 addresses structural bolting located indoors.
3.5-1, 083	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S7, "Inspection of Water- Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35) AMP is credited with managing loss of material for structural bolting exposed to outdoor air and water – flowing or standing in the Circulating Water Pumphouse.
3.5-1, 084	Item 3.5-1, 084 is deleted in NUREG-2192.				
3.5-1, 085	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191 with exception for Water Chemistry. The Water Chemistry (B.2.3.2) AMP and ASME Section XI, Subsection IWF (B.2.3.31) AMP are credited with managing loss of material for stainless bolting exposed to threated borated water in the spent fuel pool.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 086	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.S3, "ASME Section XI, Section IWF"	No	Not used. Consistent with NUREG-2191, bolted connections for ASME Class 1, 2, and 3 component supports are addressed with Item 3.5-1, 091.
3.5-1, 087	Structural bolting	Loss of preload due to self-loosening	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191 with exception. The ASME Section XI, Subsection IWF (B.2.3.31) AMP is credited with managing loss of preload for structural bolting for ASME Class 1, 2, and 3 supports.
3.5-1, 088	Structural bolting	Loss of preload due to self-loosening	AMP XI.S6, "Structures Monitoring	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing loss of preload for structural bolting exposed to uncontrolled indoor air and outdoor air.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5-1, 089	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Consistent with NUREG-2191. The Boric Acid Corrosion (B.2.3.4) AMP is credited with managing loss of material for structural steel. Miscellaneous structural components, electrical enclosures, conduit, support members, welds, bolted connections, fire dampers and louvers, crane/lifting components, and support anchorage in the Containment, Primary Auxiliary Building and Yard Structures due to potential for borated water leakage.
3.5-1, 090	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Not used. Stainless steel bolting exposed to treated borated water in the spent fuel pool is addressed in item 3.5-1, 085.
3.5-1, 091	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general, pitting corrosion	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191 with exception. The ASME Section XI, Subsection IWF (B.2.3.31) AMP is credited with managing loss of material for ASME Class 1, 2 and 3 support members, welds, bolted connections, and support anchorage.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5-1, 092	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general, pitting corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP will be used to manage loss of material for support members, welds, bolted connections, and support anchorage exposed to uncontrolled indoor air and outdoor air environments.
3.5-1, 093	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.34) AMP is credited with managing loss of material of galvanized steel supports, which are included with steel supports addressed in item 3.5-1, 092.
3.5-1, 094	Vibration isolation elements	Reduction or loss of isolation function due to radiation hardening, temperature, humidity, sustained vibratory loading	AMP XI.S3, "ASME Section XI, Subsection IWF," and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception of the ASME Section XI Subsection IWF (B.2.3.31) AMP. The ASME Section XI, Subsection IWF (B.2.3.31) AMP and Structures Monitoring (B.2.3.34) AMP are credited with managing vibration isolation elements for pertinent component supports.
3.5-1, 095	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	None	None	No	Not used. Galvanized steel is included with steel component supports addressed in item 3.5-1, 092.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 096	Groups 6: concrete (accessible areas): all	Cracking due to expansion from reaction with aggregates	AMP XI.S7, "Inspection of Water- Control Structures Associated with Nuclear Power Plants"	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35) AMP is credited with managing cracking for accessible Circulating Water Pumphouse concrete.
3.5-1, 097	Group 4: Concrete (reactor cavity area proximate to the reactor vessel): reactor (primary/biological) shield wall; sacrificial shield wall; reactor vessel support/pedestal structure	Reduction of strength; loss of mechanical properties due to irradiation (i.e., radiation interactions with material and radiation-induced heating)	Plant-specific aging Management program or other selected AMPs, enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.6)	Not applicable. A plant-specific AMP or enhancement of existing AMPs is not required. The impacts of irradiation on the primary shield wall, biological shield wall and reactor vessel support have been evaluated for end of plant life/license (the subsequent period of extended operation). The primary/biological shield wall will continue to satisfy the design criteria considering the long-term radiation effects and loss of RV support fracture toughness does not require management. The Structures Monitoring (B.2.3.34) AMP manages primary shield wall, biological shield wall, and reactor cavity liner condition. In addition, the ASME Section XI, Subsection IWF (B.2.3.31) AMP manages the aging effects for the RV support structure. Further evaluation is described in Section 3.5.2.2.2.6.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 098	Stainless steel, aluminum alloy support members; welds; bolted connections; support anchorage to building structure	None	None	No	Consistent with NUREG-2191. Stainless steel components exposed to borated water leakage do not require aging management for boric acid corrosion.
3.5-1, 099	Aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion, cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.S3, "ASME Section XI, Subsection IWF," or AMP XI.M36, "External Surfaces Monitoring of Mechanical Components	Yes (SRP-SLR Section 3.5.2.2.2.4)	Not used. Loss of material and cracking of stainless steel and aluminum is addressed in item 3.5-1, 100.

Table 3.5-1 Containment Building Structure and Internal Structural Components - Summary of Aging Management Programs					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 100	Aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion, cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.S6, "Structures Monitoring," or AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes (SRP-SLR Section 3.5.2.2.2.4)	Consistent with NUREG-2191, as clarified. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is credited with managing loss of material and cracking of stainless steel and aluminum insulation jacketing. The Structures Monitoring (B.2.3.34) AMP is credited with managing loss of material and cracking of stainless steel new fuel storage racks (refueling cavity) liners, sandbox, anchorages and ECCS strainer covers, as well as aluminum manhole manway covers exposed to air. The ASME Section XI, Subsection IWE (B.2.3.29) AMP is credited with managing loss of material for the stainless steel transfer tube. The Fire Protection (B.2.3.15) AMP is credited with managing loss of material in stainless steel fire barrier penetrations Further evaluation is documented in Section 3.5.2.2.2.4.

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Air locks, equipment hatches and accessories	Fire barrier Pressure boundary	Steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5.1-027	A
Air locks, equipment hatches and accessories	Fire barrier Pressure boundary	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.C-16	3.5-1, 028	A
Air locks, equipment hatches and accessories	Fire barrier Pressure boundary	Steel	Air – indoor uncontrolled	Loss of leak tightness	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-39	3.5-1, 029	A
Air locks, equipment hatches and accessories	Fire barrier Pressure boundary	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	C
Air locks, equipment hatches and accessories	Fire barrier Pressure boundary	Copper alloy	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5.1-027	F, 1
Air locks, equipment hatches and accessories	Fire barrier Pressure boundary	Copper alloy	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.C-16	3.5-1, 028	F, 1

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Air locks, equipment hatches and accessories	Fire barrier Pressure boundary	Elastomer	Air – indoor uncontrolled	Loss of sealing	10 CFR Part 50, Appendix J (B.2.3.32)	II.A3.CP-41	3.5-1, 033	A
Concrete Foundation / Basemat (accessible)	Direct flow Pressure boundary Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWL (B.2.3.30)	II.A1.CP-33	3.5-1, 019	A
Concrete Foundation / Basemat (accessible)	Direct flow Pressure boundary Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Increase in porosity and permeability Loss of material	ASME Section XI, Subsection IWL (B.2.3.30)	II.A1-CP-87	3.5-1, 016	A
Concrete Foundation / Basemat (accessible)	Direct flow Pressure boundary Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.34)	II.A1.CP-51	3.5-1, 018	A, 2
Concrete Foundation / Basemat (accessible)	Direct flow Pressure boundary Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	ASME Section XI, Subsection IWL (B.2.3.30)	II.A1.CP-68	3.5-1, 021	A
Concrete Foundation / Basemat (inaccessible)	Direct flow Pressure boundary Structural support	Concrete (reinforced)	Air – indoor uncontrolled Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	ASME Section XI, Subsection IWL (B.2.3.30) Structures Monitoring (B.2.3.34)	II.A1.CP-100	3.5-1, 024	A

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete Foundation / Basemat (inaccessible)	Direct flow Pressure boundary Structural support	Concrete (reinforced)	Air – outdoor Groundwater/soil	Cracking Loss of material	ASME Section XI, Subsection IWL (B.2.3.30) Structures Monitoring (B.2.3.34)	II.A1.CP-147	3.5-1, 011	A, 10
Concrete Foundation / Basemat (inaccessible)	Direct flow Pressure boundary Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	ASME Section XI, Subsection IWL (B.2.3.30) Structures Monitoring (B.2.3.34)	II.A1.CP-102	3.5-1, 014	A, 10
Concrete Foundation / Basemat (inaccessible)	Direct flow Pressure boundary Structural support	Concrete (reinforced)	Air – outdoor Groundwater/soil	Cracking	Structures Monitoring (B.2.3.34)	II.A1.CP-67	3.5-1, 012	A, 10
Concrete Foundation / Basemat (inaccessible)	Direct flow Pressure boundary Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	ASME Section XI, Subsection IWL (B.2.3.30) Structures Monitoring (B.2.3.34)	II.A1.CP-97	3.5-1, 023	A
Concrete Foundation / Basemat (inaccessible)	Direct flow Pressure boundary Structural support	Concrete (reinforced)	Soil	Cracking	ASME Section XI, Subsection IWL (B.2.3.30) Structures Monitoring (B.2.3.34)	II.A2.CP-69	3.5-1, 001	A

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete Walls, Buttresses, Dome, and Ring Girders (accessible)	Fire barrier Flood barrier Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWL (B.2.3.30)	II.A1.CP-33	3.5-1, 019	A
Concrete Walls, Buttresses, Dome, and Ring Girders (accessible)	Fire barrier Flood barrier Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Increase in porosity and permeability Loss of material	ASME Section XI, Subsection IWL (B.2.3.30)	II.A1-CP-87	3.5-1, 016	A
Concrete Walls, Buttresses, Dome, and Ring Girder (accessible)	Fire barrier Flood barrier Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.34)	II.A1.CP-31	3.5-1, 018	A, 2

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete Walls, Buttresses, Dome, and Ring Girder (accessible)	Fire barrier Flood barrier Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	ASME Section XI, Subsection IWL (B.2.3.30)	II.A1.CP-68	3.5-1, 021	A
Concrete Walls, Buttresses, Dome, and Ring Girder (inaccessible)	Fire barrier Flood barrier Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Increase in porosity and permeability Loss of material	ASME Section XI, Subsection IWL (B.2.3.30) Structures Monitoring (B.2.3.34)	II.A1.CP-100	3.5-1, 024	A
Concrete Walls, Buttresses, Dome, and Ring Girder (inaccessible)	Fire barrier Flood barrier Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.34)	II.A1.CP-67	3.5-1, 012	A, 10

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete Walls, Buttresses, Dome, and Ring Girder (inaccessible)	Fire barrier Flood barrier Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	ASME Section XI, Subsection IWL (B.2.3.30) Structures Monitoring (B.2.3.34)	II.A1.CP-97	3.5-1, 023	A
Concrete Internal Columns, Beams, Slabs, and Walls (accessible)	Fire barrier Flood barrier Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWL (B.2.3.30)	II.A1.CP-33	3.5-1, 019	A
Concrete Internal Columns, Beams, Slabs, and Walls (accessible)	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Increase in porosity and permeability Loss of material	ASME Section XI, Subsection IWL (B.2.3.30)	II.A1-CP-87	3.5-1, 016	A

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete Internal Columns, Beams, Slabs, and Walls (accessible)	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	ASME Section XI, Subsection IWL (B.2.3.30)	II.A1.CP-68	3.5-1, 021	A
Concrete Internal Columns, Beams, Slabs, and Walls (inaccessible)	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Increase in porosity and permeability Loss of material	ASME Section XI, Subsection IWL (B.2.3.30) Structures Monitoring (B.2.3.34)	II.A1.CP-100	3.5-1, 024	A
Concrete Internal Columns, Beams, Slabs, and Walls (inaccessible)	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.34)	II.A1.CP-67	3.5-1, 012	A, 10
Concrete Internal Columns, Beams, Slabs, and Walls (inaccessible)	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	ASME Section XI, Subsection IWL (B.2.3.30) Structures Monitoring (B.2.3.34)	II.A1.CP-97	3.5-1, 023	A

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete Tendon Gallery Walls (accessible)	Shelter, protection	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A, 3
Concrete Tendon Gallery Walls (accessible)	Shelter, protection	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-28	3.5-1, 067	A, 3
Concrete Tendon Gallery Walls (accessible)	Shelter, protection	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A, 3
Concrete Tendon Gallery Walls (accessible)	Shelter, protection	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A, 3
Concrete Tendon Gallery Walls (accessible)	Shelter, protection	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-26	3.5-1, 066	A, 3
Concrete Tendon Gallery Walls (inaccessible)	Shelter, protection	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-29	3.5-1, 067	A, 3
Concrete Tendon Gallery Walls (inaccessible)	Shelter, protection	Concrete (reinforced)	Air – outdoor Groundwater/soil	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-108	3.5-1, 042	A, 3, 10
Concrete Tendon Gallery Walls (inaccessible)	Shelter, protection	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-67	3.5-1, 047	A, 3, 10

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete Tendon Gallery Walls (inaccessible)	Shelter, protection	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 3, 10
Concrete Tendon Gallery Walls (inaccessible)	Shelter, protection	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-26	3.5-1, 065	A, 3
Concrete Tendon Gallery Walls (inaccessible)	Shelter, protection	Concrete (reinforced)	Soil	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-30	3.5-1, 044	A, 3
Construction Truss	Structural Support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A4.TP-302	3.5-1, 077	A
Construction Truss	Structural Support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	A
H-Piles	Structural support	Steel	Groundwater/soil	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-219	3.5-1, 079	A
Fuel transfer tube (including penetration sleeves, expansion joints, and blind flange)	Fire barrier Pressure boundary Radiation shielding	Stainless steel	Treated borated water	Loss of material	One-Time Inspection (B.2.3.20) Water Chemistry (B.2.3.2)	VII.A2.AP-79	3.3-1, 125	D
Fuel transfer tube (including penetration sleeves, expansion joints, and blind flange)	Fire barrier Pressure boundary Radiation shielding	Stainless steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-38	3.5-1, 010	A

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Fuel transfer tube (including penetration sleeves, expansion joints, and blind flange)	Fire barrier Pressure boundary Radiation shielding	Stainless steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29)	III.B3.T-37b	3.5-1, 100	E, 4
Liners (refueling cavity) and covers (sand box, Unit 1 sump A strainer)	Direct flow Fire barrier Pressure boundary Radiation shielding	Stainless steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.B3.T-37b	3.5-1, 100	E, 4
Liners (refueling cavity) and covers (sand box, Unit 1 sump A strainer)	Direct flow Fire barrier Pressure boundary Radiation shielding	Stainless steel	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.34)	III.B3.T-37b	3.5-1, 100	E, 4
Liners (reactor cavity)	Radiation shielding Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	VII.A1.A-94	3.3-1, 111	C
Liners (reactor cavity)	Radiation shielding Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	C
Liner plate	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA – Section 4.6, Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis	II.A3.C-13	3.5-1, 009	A

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Liner plate (accessible)	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A1.CP-35	3.5-1, 035	A
Liner plate (inaccessible)	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A1.CP-98	3.5-1, 005	A
Liner plate and keyway channel (accessible)	Direct flow Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A1.CP-35	3.5-1, 035	A
Liner plate and keyway channel (inaccessible)	Direct flow Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A1.CP-98	3.5-1, 005	A
Liner plate anchors and attachments (accessible)	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A1.CP-35	3.5-1, 035	A
Liner plate anchors and attachments (inaccessible)	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A1.CP-98	3.5-1, 005	A

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Liner plate, anchors and attachments	Direct flow Pressure boundary Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	C
Liner plate moisture barrier (sealing compound)	Shelter, protection	Elastomer	Air – indoor uncontrolled	Loss of sealing	ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-40	3.5-1, 026	A, 5
Miscellaneous structural components	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	VII.A1.A-94	3.3-1, 111	A
Miscellaneous structural components	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	A
Penetration assemblies	Structural support Pressure boundary	Elastomer	Air – indoor uncontrolled	Loss of sealing	10 CFR Part 50, Appendix J (B.2.3.32)	II.A3.CP-41	3.5-1, 033	A
Penetration sleeves (Electrical)	Structural support Pressure boundary	Steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A
Penetration sleeves (Electrical)	Structural support Pressure boundary	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-36	3.5-1, 035	A

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Penetration assemblies (Electrical)	Fire barrier Pressure boundary Structural support	Dissimilar metal welds	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A
Penetration assemblies (Electrical)	Fire barrier Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A
Penetration sleeves (Mechanical)	Structural support Pressure boundary	Steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA – Section 4.6, Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis	II.A3.C-13	3.5-1, 009	A
Penetration assemblies (Mechanical)	Structural support Pressure boundary	Steel	Air with borated water leakage	Loss of Material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	C
Penetration assemblies (Mechanical)	Structural support Pressure boundary	Steel	Air – indoor uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-36	3.5-1, 035	A
Penetration assemblies (Mechanical)	Structural support Pressure boundary	Dissimilar metal welds	Air – indoor uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-36	3.5-1, 035	A

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Penetration assemblies (Mechanical)	Structural support Pressure boundary	Dissimilar metal welds	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-38	3.5-1, 010	A
Penetration assemblies (Mechanical)	Structural support Pressure boundary	Stainless steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A
Penetration assemblies (Mechanical)	Structural support Pressure boundary	Stainless steel	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.32)	II.A3.CP-38	3.5-1, 010	A
Pressure retaining bolting	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-148	3.5-1, 031	A
Pressure retaining bolting	Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-148	3.5-1, 031	A
Pressure retaining bolting	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of preload	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-150	3.5-1, 030	A

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pressure retaining bolting	Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled	Loss of preload	10 CFR Part 50, Appendix J (B.2.3.32) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-150	3.5-1, 030	A
Primary shield wall (and biological shield wall)	Radiation Shielding Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Loss of mechanical properties Reduction of strength	Structures Monitoring (B.2.3.34)	III.A4.T-35	3.5-1, 097	A, 7, 10
Radiant energy shields	Fire barrier	Stainless steel	Air with borated water leakage	None	None	III.B5.TP-4	3.5-1, 098	C
Radiant energy shields	Fire barrier	Stainless steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.B3.T-37b	3.5-1, 100	E, 4
Radiant energy shields	Fire barrier	Stainless steel	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.34)	III.B3.T-37b	3.5-1, 100	E, 4
RC Class 1 supports	Structural support	Steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B.2.3.31)	III.B1.1.T-24	3.5-1, 091	B, 8
RC Class 1 supports	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	C
RC Class 1 support bolting	Structural support	High-strength steel	Air with borated water leakage	Loss of Material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	C
RC Class 1 support bolting	Structural support	High-strength steel	Air – indoor uncontrolled	Loss of preload	ASME Section XI, Subsection IWF (B.2.3.31)	III.B1.1.TP-229	3.5-1, 087	B, 8
RC Class 1 support bolting	Structural support	High-strength steel	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.3.31)	III.B1.1.TP-41	3.5-1, 068	B, 8

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reactor cavity seal ring	Pressure Boundary	Stainless steel	Treated borated water	Loss of material	One-Time Inspection (B.2.3.20) Water Chemistry (B.2.3.2)	VII.A2.A-99	3.3-1, 125	D
Refueling components (containment upender, davit arm)	Structural support	Stainless steel	Treated borated water	Loss of material	One-Time Inspection (B.2.3.20) Water Chemistry (B.2.3.2)	VII.A2.A-99	3.3-1, 125	D
Service Level I coatings	Maintain adhesion	Coatings	Air – indoor uncontrolled	Loss of coating or lining integrity	Protective Coating Monitoring and Maintenance (B.2.3.36)	II.A3.CP-152	3.5-1, 034	A
Sliding Surfaces	Structural support	Lubrite®	Air – indoor uncontrolled	Loss of mechanical function	Structures Monitoring (B.2.3.34)	III.B2.TP-46	3.5-1, 074	A
Tendons (post-tensioning system)	Structural support	Steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWL (B.2.3.30)	II.A1.C-10	3.5-1, 032	A
Tendons (post-tensioning system)	Structural support	Steel	Air – indoor uncontrolled	Loss of prestress	TLAA – Section 4.5, Concrete Containment Tendon Prestress	II.A1.C-11	3.5-1, 008	A
Tendons (post-tensioning system)	Structural support	Steel	Air with borated water leakage	Loss of Material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	C
Tendon anchorage and attachments	Structural support	Steel	Air with borated water leakage	Loss of Material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	C

Table 3.5.2-1: Containment Building Structure and Internal Structural Components - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tendon anchorage and attachments	Structural support	Steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWL (B.2.3.30)	II.A1.C-10	3.5-1, 032	A
Thermal insulation (high temperature penetrations)	Insulate (thermal)	Calcium silicate, amosite asbestos with a silicate binder	Air – indoor uncontrolled	None	None	VIII.H.S-403	3.4-1, 064	I, 9

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

F. Material not in NUREG-2191 for this component.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

Plant Specific Notes

1. Copper alloy is not addressed as a structural component in NUREG-2191. However, the environment, aging effects (cracking and loss of material) and aging management programs for steel air lock, hatch components are conservatively also applicable to the copper alloy airlock bushings.
2. PBN containments are located entirely inside the Façade building and are not associated with an air – outdoor environment. However, freeze-thaw conditions are still possible during winter months where water or groundwater collects as the Façade building is non-heated.
3. The tendon gallery adjacent to each PBN Unit's containment, inside the Façade building, is part of the containment basemat in the top few feet. The tendon galleries are not associated with an air – outdoor environment. However, freeze thaw conditions are still possible during winter months where water or groundwater collects as the Façade building is non-heated.
4. Structural stainless steel that is exposed to air – indoor uncontrolled during normal plant operation is inspected under the Structures Monitoring (B.2.3.34) AMP, or in the case of the transfer canal the ASME Section XI, Subsection IWE (B.2.3.29) AMP, the structural equivalent of the NUREG-2191 XI.M36, Externals Surfaces Monitoring of Mechanical Components AM.
5. Liner moisture barriers are at the junction where the liner is embedded in the concrete slab and for the core holes in the concrete slab that allow inspection of the liner.
6. Penetration assemblies for high temperature stainless steel piping systems only, whereas other mechanical penetration sleeves/assemblies are addressed for cumulative fatigue damage.
7. Primary shield wall, and attached biological shield wall, with a ¼ inch steel liner surrounds the reactor cavity and the reactor vessel support structure passes through and is attached to it at certain points. Existing inspections, through the Structures Monitoring (B.2.3.34) AMP, manage the condition of the shield wall.
8. As described in the RAI responses/supplements for the first 2 PWRs with renewed licenses for 80 years, thermal embrittlement of the steel reactor vessel support structure columns and beams requires analysis. Existing inspections, through the ASME Section XI, Subsection IWF (B.2.3.31) AMP, manages the condition of the reactor vessel support.
9. Insulation for main steam and feedwater penetrations are encased in steel penetration covers in the annulus and there are no plausible aging effects that could degrade the calcium silicate or amosite asbestos (with a silicate binder) insulation. Furthermore, temperature measurements for the penetrations are within UFSAR allowable.
10. Based on SLR-ISG-Structures-2020-XX, "Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance", the existing Structures Monitoring (B.2.3.34) AMP is credited rather than a plant-specific AMP and is supplemented by the ASME Section XI, Subsection IWL (B.2.3.32) AMP as appropriate.

Table 3.5.2-2: Circulating Water Pumphouse Structure – Summary of Aging Management Evaluation

Table 3.5.2-2: Circulating Water Pumphouse Structure - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Water - flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35)	III.A6.T-20	3.5-1, 056	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A6.TP-104	3.5-1, 065	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.34)	III.A6.TP-220	3.5-1, 050	A, 1
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A6.TP-30	3.5-1, 044	A
Concrete: basemat, foundation (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A6.TP-110	3.5-1, 049	A, 1
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A6.TP-107	3.5-1, 067	A
Concrete: external walls and roof (accessible)	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor Water - flowing	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35)	III.A6.T-34	3.5-1, 096	A

Table 3.5.2-2: Circulating Water Pumphouse Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: external walls and roof (accessible)	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor Water - flowing	Increase in porosity and permeability Loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35)	III.A6.TP-37	3.5-1, 061	A
Concrete: external walls and roof (accessible)	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor Water - flowing	Cracking Loss of bond Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35)	III.A6.TP-38	3.5-1, 059	A
Concrete: external walls and roof (accessible)	Fire barrier Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor Water - flowing	Cracking Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35)	III.A6.TP-36	3.5-1, 060	A
Concrete: forebay structure and pump bay (accessible)	Direct flow Flood barrier Shelter, protection Structural support	Concrete (reinforced)	Water - flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35)	III.A6.T-20	3.5-1, 056	A
Concrete: forebay structure and pump bay (inaccessible)	Direct flow Flood barrier Shelter, protection Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A6.TP-109	3.5-1, 051	A, 1

Table 3.5.2-2: Circulating Water Pumphouse Structure - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: forebay structure and pump bay (inaccessible)	Direct flow Flood barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor Groundwater/soil	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A6.TP-110	3.5-1, 049	A, 1
Concrete: internal columns, floors, and walls	Fire barrier Heat sink Structural support	Concrete (reinforced)	Water - flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35)	III.A6.T-20	3.5-1, 056	A
Concrete: internal columns, floors, and walls	Fire barrier Heat sink Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material	Fire Protection (B.2.3.15) and Structures Monitoring (B.2.3.34)	VII.G.A-90	3.3-1, 060	A
Fire rated doors	Fire barrier	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Fire Protection (B.2.3.15)	VII.G.A-21	3.3-1, 059	A
Miscellaneous structural components	Missile barrier Flood barrier Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.B5.TP-43	3.5-1, 092	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor Water - flowing or standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.35)	III.A6.TP-221	3.5-1, 083	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor Water - flowing or standing	Loss of preload	Structures Monitoring (B.2.3.34)	III.A6.TP-261	3.5-1, 088	A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

1. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PBN credits an existing AMP based on SLR-ISG-Structures-2020-XX, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.

Table 3.5.2-3: Control Building Structure – Summary of Aging Management Evaluation

Table 3.5.2-3: Control Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A1.TP-25	3.5-1, 054	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A1.TP-23	3.5-1, 064	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A1.TP-27	3.5-1, 065	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A1.TP-24	3.5-1, 063	A, 1
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.34)	III.A1.TP-204	3.5-1, 043	A, 3
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A1.TP-212	3.5-1, 065	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A1.TP-29	3.5-1, 067	A

Table 3.5.2-3: Control Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A1.TP-108	3.5-1, 042	A, 3
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A1.TP-30	3.5-1, 044	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A1.TP-67	3.5-1, 047	A, 2, 3
Concrete: exterior walls and roof	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A1.TP-25	3.5-1, 054	A
Concrete: exterior walls and roof	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A1.TP-23	3.5-1, 064	A
Concrete: exterior walls and roof	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A1.TP-26	3.5-1, 066	A
Concrete: interior walls, ceilings, floors	Fire barrier Flood barrier Heat sink HELB shielding Missile barrier Radiation shielding Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection (B.2.3.15) and Structures Monitoring (B.2.3.34)	VII.G.A-90	3.3-1, 060	A

Table 3.5.2-3: Control Building Structure – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Door seals	Flood barrier	Elastomer	Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B.2.3.34)	III.A6.TP-7	3.5-1, 072	C
Fire rated doors	Fire barrier Flood barrier	Steel	Air – indoor uncontrolled	Loss of Material	Fire Protection (B.2.3.15)	VII.G.A-21	3.3-1, 059	A
Glass windows	HELB shielding Shelter, protection	Glass	Air – indoor uncontrolled Air – outdoor	None	None	VII.J.AP-48	3.3-1, 117	C
Masonry (block) walls	Fire barrier Structural support	Concrete block	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection (B.2.3.15) and Masonry Walls (B.2.3.33)	VII.G.A-626	3.3-1, 179	A
Miscellaneous structural components	Flood barrier HELB shielding Missile barrier Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A1.TP-302	3.5-1, 077	A
Miscellaneous structural components	Flood barrier HELB shielding Missile barrier Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A1.TP-302	3.5-1, 077	A
Penetration seals	Pressure boundary	Elastomer	Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B.2.3.34)	III.A6.TP-7	3.5-1, 072	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.34)	III.A1-TP-261	3.5-1, 088	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A1-TP-274	3.5-1, 082	A
Wooden beams	Missile barrier	Wood	Air – outdoor	Change in material properties Loss of material	Structures Monitoring (B.2.3.34)	III.A6-TP-223	3.5-1, 062	E, 4

General Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes

1. Rainfall tends to wash surfaces. However, times of significant precipitation or areas of water collection/flowing such as ground/wall interfaces are conservatively susceptible to leaching.
2. Groundwater is considered to be water-flowing.
3. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PBN credits an existing AMP based on SLR-ISG-Structures-2020-XX, "Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance".
4. Wooden beams and framing in the yard protect the air intake of the Train A emergency diesel generator located in the Control Building.

Table 3.5.2-4: Diesel Generator Building Structure – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A, 1
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Air - outdoor	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A3.TP-30	3.5-1, 044	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Soil	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A

Table 3.5.2-4: Diesel Generator Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-26	3.5-1, 066	A
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-28	3.5-1, 067	A
Concrete: exterior walls and roof (inaccessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 2
Concrete: interior walls, ceiling, and floor	Fire barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection (B.2.3.15) and Structures Monitoring (B.2.3.34)	VII.G.A-90	3.3-1, 060	A
Fire rated doors	Fire barrier Structural support	Steel	Air – outdoor	Loss of material	Fire Protection (B.2.3.15)	VII.G.A-21	3.3-1, 059	A

Table 3.5.2-4: Diesel Generator Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Joint and Penetration seals	Shelter, protection	Elastomer	Air – indoor uncontrolled Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.34)	III.A6.TP-7	3.5-1, 072	A
Louver and exhaust hoods	Shelter, protection	Steel	Air - outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.B2.TP-6	3.5-1, 093	A
Masonry (block) walls	Fire barrier	Concrete block	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection (B.2.3.15) Masonry Walls (B.2.3.33)	VII.G.A-626	3.3-1, 179	A
Masonry (block) walls	Flood Barrier Structural support	Concrete block	Air – indoor uncontrolled Air – outdoor	Cracking	Masonry Walls (B.2.3.33)	III.A3.T-12	3.5-1, 070	A
Miscellaneous structural components	Missile barrier Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-302	3.5-1, 077	A
Miscellaneous structural components	Structural support Missile barrier	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-302	3.5-1, 077	A, 3
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.34)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-274	3.5-1, 082	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

1. Rainfall tends to wash surfaces. However, times of significant precipitation or areas of water collection/flowing such as ground/wall interfaces are conservatively susceptible to leaching.
2. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PBN credits an existing based on SLR-ISG-Structures-2020-XX, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.
3. Wind barrier in the yard protects the exhaust of the Train B emergency diesel generator in the Diesel Generator Building.

Table 3.5.2-5: Facade Units 1//2 Structure– Summary of Aging Management Evaluation

Table 3.5.2-5: Facade Units 1/2 Structure– Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A, 1
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-27	3.5-1, 065	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 3
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-29	3.5-1, 067	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Loss of material Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-108	3.5-1, 042	A, 3
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A3.TP-30	3.5-1, 044	A

Table 3.5.2-5: Facade Units 1/2 Structure– Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: basemat, foundation (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-212	3.5-1, 065	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-67	3.5-1, 047	A, 2, 3
Concrete: exterior walls (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: exterior walls (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A
Concrete: exterior walls (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-26	3.5-1, 066	A
Concrete: exterior walls (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: exterior walls (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-28	3.5-1, 067	A
Concrete: exterior walls (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 3
Concrete: interior walls	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Masonry (block) walls	Shelter, protection Structural support	Concrete block	Air – indoor uncontrolled	Cracking	Masonry Walls (B.2.3.33)	III.A3.T-12	3.5-1, 070	A

Table 3.5.2-5: Facade Units 1/2 Structure– Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural steel and miscellaneous structural components	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.34)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-248	3.5-1, 080	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

1. Rainfall tends to wash surfaces. However, times of significant precipitation or areas of water collection/flowing such as ground/wall interfaces are conservatively susceptible to leaching.
2. Groundwater is considered to be water-flowing.
3. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PBN credits an existing AMP consistent with SLR-ISG-Structures-2020-XX, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.

Table 3.5.2-6: Fuel Oil Pumphouse Structure – Summary of Aging Management Evaluation

Table 3.5.2-6: Fuel Oil Pumphouse Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A, 1
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-27	3.5-1, 065	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 3
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-29	3.5-1, 067	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-108	3.5-1, 042	A, 3
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A3.TP-30	3.5-1, 044	A

Table 3.5.2-6: Fuel Oil Pumphouse Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: basemat, foundation (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-212	3.5-1, 065	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-67	3.5-1, 047	A, 2, 3
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A, 1
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-26	3.5-1, 066	A
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A

Table 3.5.2-6: Fuel Oil Pumphouse Structure – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-28	3.5-1, 067	A
Concrete: exterior walls and roof (inaccessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 3
Concrete: interior walls, ceilings, and roof	Fire barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection (B.2.3.15) and Structures Monitoring (B.2.3.34)	VII.G.A-90	3.3-1, 060	A
Masonry (block) walls	Fire barrier Shelter, protection Structural support	Concrete block	Air – outdoor	Cracking	Masonry Walls (B.2.3.33)	III.A3.T-12	3.5-1, 070	A
Masonry (block) walls	Fire barrier Shelter, protection Structural support	Concrete block	Air – outdoor	Cracking Loss of material	Masonry Walls (B.2.3.33)	III.A3.TP-34	3.5-1, 071	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.34)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-248	3.5-1, 080	A

Table 3.5.2-6: Fuel Oil Pumphouse Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-274	3.5-1, 082	A
Structural steel and miscellaneous structural components	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-302	3.5-1, 077	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

1. Rainfall tends to wash surfaces. However, times of significant precipitation or areas of water collection/flowing such as ground/wall interfaces are conservatively susceptible to leaching.
2. Groundwater is considered to be water-flowing.
3. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PBN credits an existing AMP consistent with SLR-ISG-Structures-2020-XX, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.

Table 3.5.2-7: Gas Turbine Building Structure – Summary of Aging Management Evaluation

Table 3.5.2-7: Gas Turbine Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A, 1
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A3.TP-30	3.5-1, 044	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 2
Concrete: exterior walls (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: exterior walls (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-26	3.5-1, 066	A

Table 3.5.2-7: Gas Turbine Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: exterior walls (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: exterior walls (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-28	3.5-1, 067	A
Concrete: exterior walls (inaccessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 2
Concrete: interior walls	Fire barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection (B.2.3.15) and Structures Monitoring (B.2.3.34)	VII.G.A-90	3.3-1, 060	A
Structural steel and miscellaneous structural components	Shelter, protection Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.34)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural support	Steel	Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.34)	III.A3.TP-261	3.5-1, 088	A

Table 3.5.2-7: Gas Turbine Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-274	3.5-1, 082	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

1. Rainfall tends to wash surfaces. However, times of significant precipitation or areas of water collection/flowing such as ground/wall interfaces are conservatively susceptible to leaching.
2. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PBN credits an existing AMP consistent with SLR-ISG-Structures-2020-XX, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.

Table 3.5.2-8: Primary Auxiliary Building Structure – Summary of Aging Management Evaluation

Table 3.5.2-8: Primary Auxiliary Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A, 1
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-27	3.5-1, 065	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 3
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-29	3.5-1, 067	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-108	3.5-1, 042	A, 3
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A3.TP-30	3.5-1, 044	A

Table 3.5.2-8: Primary Auxiliary Building Structure – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: basemat, foundation (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-212	3.5-1, 065	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-67	3.5-1, 047	A, 2, 3
Concrete: exterior walls and roof	Fire barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Fire Protection (B.2.3.15) and Structures Monitoring (B.2.3.34)	VII.G.A-90	3.3-1, 060	A
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-26	3.5-1, 066	A
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: exterior walls and roof (accessible)	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-28	3.5-1, 067	A

Table 3.5.2-8: Primary Auxiliary Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: exterior walls and roof (inaccessible)	Structural support Shelter, protection Missile barrier Flood barrier	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 3
Concrete: interior walls, ceiling, and floors	Fire barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection (B.2.3.15) and Structures Monitoring (B.2.3.34)	VII.G.A-90	3.3-1, 060	A
Fire rated doors	Fire barrier Flood barrier	Steel	Air – indoor uncontrolled	Loss of material	Fire Protection (B.2.3.15)	VII.G.A-21	3.3-1, 059	A
Louver and exhaust hoods	Shelter, protection	Steel	Air - outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.B2.TP-6	3.5-1, 093	A
Masonry (block) walls	Fire barrier Structural support	Concrete block	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection (B.2.3.15) and Masonry Walls (B.2.3.33)	VII.G.A-626	3.3-1, 179	A
Masonry (block) walls	Structural support	Concrete block	Air – indoor uncontrolled	Cracking	Masonry Walls (B.2.3.33)	III.A3.T-12	3.5-1, 070	A
Structural steel and miscellaneous structural components	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.TP-3	3.5-1, 089	A
Structural steel and miscellaneous structural components	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-302	3.5-1, 077	A
New fuel storage racks	Structural support	Stainless steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.B3.T-37b	3.5-1, 100	A
Penetration seals	Fire barrier Flood barrier	Elastomer	Air – indoor uncontrolled	Hardening Loss of strength Shrinkage	Fire Protection (B.2.3.15)	VII.G.A-19	3.3-1, 057	A

Table 3.5.2-8: Primary Auxiliary Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Penetration seals	Fire barrier Flood barrier	Elastomer	Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B.2.3.34)	III.A6.TP-7	3.5-1, 072	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.34)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-274	3.5-1, 082	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

1. Rainfall tends to wash surfaces. However, times of significant precipitation or areas of water collection/flowing such as ground/wall interfaces are conservatively susceptible to leaching.
2. Groundwater is considered to be water-flowing.
3. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PBN credits an existing AMP consistent with SLR-ISG-Structures-2020-XX, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.

Table 3.5.2-9: Spent Fuel Pool Structure – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A5.TP-212	3.5-1, 065	A
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.34)	III.A5.TP-204	3.5-1, 043	A, 3
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A5.TP-30	3.5-1, 044	A
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A5.TP-67	3.5-1, 047	A, 1
Concrete: spent fuel pool, transfer canal walls (accessible)	Flood barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.34)	III.A5.TP-25	3.5-1, 054	A
Concrete: spent fuel pool, transfer canal walls (accessible)	Flood barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A5.TP-26	3.5-1, 066	A
Concrete: spent fuel pool, transfer canal walls (inaccessible)	Flood barrier Shelter, protection Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A5.TP-67	3.5-1, 047	A, 2, 3
H-piles	Structural support	Steel	Soil	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-219	3.5-1, 079	A

Table 3.5.2-9: Spent Fuel Pool Structure – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Liner	Pressure boundary	Stainless steel	Treated borated water	Cracking Loss of material	Water Chemistry (B.2.3.2) and monitoring of the spent fuel pool water level and leakage from the leak chase channels	III.A5.T-14	3.5-1, 078	A
Miscellaneous structural components	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B5.T-25	3.5-1, 089	A
Seals	Pressure boundary	Elastomer	Treated borated water	Loss of sealing	Structures Monitoring (B.2.3.34)	III.A6.TP-7	3.5-1, 072	A
Spent fuel pool upender	Structural support	Stainless steel	Treated borated water	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.A-99	3.3-1, 125	C
Spent fuel storage racks	Structural support	Stainless steel	Treated borated water	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.A-99	3.3-1, 125	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.34)	III.A6.TP-261	3.5-1, 088	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A6.TP-248	3.5-1, 080	A
Structural bolting	Structural support	Stainless steel	Treated borated water	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	III.A6.TP-221	3.5-1, 085	A
Transfer canal gates	Pressure boundary	Stainless steel	Treated borated water	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.A-99	3.3-1, 125	C

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

1. Groundwater is considered to be water- flowing.
2. Conservatively, spent fuel pool leakage is identified as water-flowing.

3. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PBN credits an existing AMP consistent with SLR-ISG-Structures-2020-XX, "Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance".

Table 3.5.2-10: Turbine Building Structure – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A, 1
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-27	3.5-1, 065	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 3
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-29	3.5-1, 067	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-108	3.5-1, 042	A, 3
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A3.TP-30	3.5-1, 044	A
Concrete: basemat, foundation (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-212	3.5-1, 065	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-67	3.5-1, 047	A, 2, 3

Table 3.5.2-10: Turbine Building Structure – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: exterior walls and roof (accessible)	Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: exterior walls and roof (accessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A, 1
Concrete: exterior walls and roof (accessible)	Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-26	3.5-1, 066	A
Concrete: exterior walls and roof (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: exterior walls and roof (accessible)	Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Increase in porosity and permeability Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-28	3.5-1, 067	A
Concrete: exterior walls and roof (inaccessible)	Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 3
Concrete: interior walls and ceilings	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection (B.2.3.15) and Structures Monitoring (B.2.3.34)	VII.G.A-90	3.3-1, 060	A
Masonry (block) walls	Fire barrier Structural support	Concrete block	Air – indoor uncontrolled	Cracking Loss of material	Fire Protection (B.2.3.15) and Masonry Walls (B.2.3.33)	VII.G.A-626	3.3-1, 179	A
Structural steel and miscellaneous structural components	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.34)	III.A3.TP-261	3.5-1, 088	A

Table 3.5.2-10: Turbine Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-274	3.5-1, 082	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

1. Rainfall tends to wash surfaces. However, times of significant precipitation or areas of water collection/flowing such as ground/wall interfaces are conservatively susceptible to leaching.
2. Groundwater is considered to be water-flowing.
3. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PBN credits an existing AMP consistent with SLR-ISG-Structures-2020-XX, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.

Table 3.5.2-11: Yard Structures – Summary of Aging Management Evaluation

Table 3.5.2-11: Yard Structures – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Berm	Fire barrier	Earth	Air – outdoor	Loss of form Loss of material	Structures Monitoring (B.2.3.34)	-	-	J, 4
Concrete duct banks, manholes, trenches (inaccessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-67	3.5-1, 047	A, 1, 5
Concrete duct banks, manholes, trenches	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-29	3.5-1, 067	A
Concrete duct banks, manholes, trenches	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-27	3.5-1, 065	A
Concrete duct banks, manholes, trenches	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-26	3.5-1, 066	A
Concrete duct banks, manholes, trenches	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor Soil	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A
Concrete duct banks, manholes, trenches	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A, 2
Concrete Foundations (accessible)	Structural support	Concrete (reinforced)	Soil	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A3.TP-30	3.5-1, 044	A
Concrete Foundations (inaccessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A

Table 3.5.2-11: Yard Structures – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete Foundations (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-29	3.5-1, 067	A
Manholes	Fire barrier	Concrete Block	Air – outdoor	Cracking Loss of material	Fire Protection (B.2.3.15) and Masonry Walls (B.2.3.33)	VII.G.A-626	3.3-1, 179	A
Manholes	Fire barrier	Concrete Block	Soil	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A3.TP-30	3.5-1, 044	C, 3
Manway insulation boards	Structural support	Styrofoam	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	-	-	J
Miscellaneous structural components	Fire barrier Shelter, protection Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-302	3.5-1, 077	A
Miscellaneous structural components	Structural support	Stainless steel	Air – outdoor	Loss of material Cracking	Structures Monitoring (B.2.3.34)	III.B5.T-37b	3.5-1, 100	A
Miscellaneous structural components	Structural support	Aluminum	Air – outdoor	Loss of material Cracking	Structures Monitoring (B.2.3.34)	III.B5.T-37b	3.5-1, 100	A
Miscellaneous structural components	Fire barrier Shelter, protection Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.TP-3	3.5-1, 089	A
Structural bolting	Structural support	Steel	Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.34)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-248	3.5-1, 080	A

Table 3.5.2-11: Yard Structures – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-274	3.5-1, 082	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes

1. Groundwater is considered to be water- flowing.
2. Rainfall tends to wash surfaces. However, times of significant precipitation or areas of water collection/flowing such as ground/wall interfaces are conservatively susceptible to leaching.
3. Consistent with the currently renewed licenses, concrete block manholes are underground and exposed to soil.
4. Berm surrounding the fuel oil storage tanks provides a fire barrier.
5. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PBN credits an existing AMP consistent with SLR-ISG-Structures-2020-XX, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.

Table 3.5.2-12: 13.8 kV Switchgear Building Structure – Summary of Aging Management Evaluation

Table 3.5.2-12: 13.8 kV Switchgear Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A, 1
Concrete: basemat, foundation (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 2
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-108	3.5-1, 042	A, 2
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Distortion	Structures Monitoring (B.2.3.34)	III.A3.TP-30	3.5-1, 044	A
Concrete: basemat, foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-212	3.5-1, 065	A
Concrete: exterior walls and roof (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-25	3.5-1, 054	A

Table 3.5.2-12: 13.8 kV Switchgear Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: exterior walls and roof (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Water - flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.34)	III.A3.TP-24	3.5-1, 063	A
Concrete: exterior walls and roof (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-26	3.5-1, 066	A
Concrete: exterior walls and roof (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-23	3.5-1, 064	A
Concrete: exterior walls and roof (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-28	3.5-1, 067	A
Concrete: exterior walls and roof (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.34)	III.A3.TP-204	3.5-1, 043	A, 2
Masonry (block) walls	Structural support	Concrete block	Air – indoor uncontrolled	Cracking	Masonry Walls (B.2.3.33)	III.A3.T-12	3.5-1, 070	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.34)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-274	3.5-1, 082	A

Table 3.5.2-12: 13.8 kV Switchgear Building Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural steel and miscellaneous structural components	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-302	3.5-1, 077	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

1. Rainfall tends to wash surfaces. However, times of significant precipitation or areas of water collection/flowing such as ground/wall interfaces are conservatively susceptible to leaching.
2. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PBN credits an existing AMP consistent with SLR-ISG-Structures-2020-XX, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.

Table 3.5.2-13: Component Supports Commodity Group – Summary of Aging Management Evaluation

Table 3.5.2-13: Component Supports Commodity Group – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage / embedment	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.34)	III.A3.TP-261	3.5-1, 088	A
Anchorage / embedment	Structural Support	Stainless steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.B3.T-37b	3.5-1, 100	A
Anchorage / embedment	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.B3.TP-248	3.5-1, 080	A
Anchorage / embedment	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	A
ASME Class 2 and 3 structural bolting	Structural support	High-strength steel	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.3.31)	III.B1.1.TP-41	3.5-1, 068	B, 1
ASME Class 2 and 3 structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	ASME Section XI, Subsection IWF (B.2.3.31)	III.B1.2.TP-229	3.5-1, 087	B, 1
ASME Class 2 and 3 supports	Pipe whip restraint Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.T-25	3.5-1, 089	B, 1
ASME Class 2 and 3 supports	Pipe whip restraint Structural support	Steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B.2.3.31)	III.B1.1.T-24	3.5-1, 091	B, 1
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring (B.2.3.34)	III.B2.TP-42	3.5-1, 055	A

Table 3.5.2-13: Component Supports Commodity Group – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete (reinforced)	Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring (B.2.3.34)	III.B2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Grout	Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring (B.2.3.34)	III.B2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Grout	Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring (B.2.3.34)	III.B2.TP-42	3.5-1, 055	A
Component supports	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.B4.T-43	3.5-1, 092	A
Component supports	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B4.T-25	3.5-1, 089	A
Electrical Enclosures – Panels, boxes, cabinets, consoles, raceways	Shelter, protection Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B3.T-25	3.5-1, 089	A

Table 3.5.2-13: Component Supports Commodity Group – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Electrical Enclosures – Panels, boxes, cabinets, consoles, raceways	Shelter, protection Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.B3.T-43	3.5-1, 092	A
Insulation	Insulation Jacket integrity	Stainless Steel	Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	III.B2.T-37c	3.5-1, 100	C
Insulation	Insulation Jacket integrity	Aluminum	Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	III.B2.T-37c	3.5-1, 100	C
Insulation	Insulation Jacket integrity	Stainless Steel	Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	III.B2.T-37c	3.5-1, 100	C
Insulation	Insulation Jacket integrity	Aluminum	Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	III.B2.T-37c	3.5-1, 100	C
Pipe restraints and HVAC duct supports	Pipe whip restraint Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B2.T-25	3.5-1, 089	A
Pipe restraints and HVAC duct supports	Pipe whip restraint Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.B2.TP-43	3.5-1, 092	A

Table 3.5.2-13: Component Supports Commodity Group – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.34)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.34)	III.B3.TP-248	3.5-1, 080	A
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.34)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural support	High-strength steel	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.34)	III.B1.1.TP-41	3.5-1, 068	E
Vibration isolation elements	Structural support	Non-metallic; Elastomer	Air – indoor uncontrolled	Reduction or loss of isolation function	ASME Section XI, Subsection IWF (B.2.3.31)	III.B1.1.T-33	3.5-1, 094	B
Vibration isolation elements	Structural support	Non-metallic; Elastomer	Air – indoor uncontrolled	Reduction or loss of isolation function	Structures Monitoring (B.2.3.34)	III.B4.TP-44	3.5-1, 094	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

Plant Specific Notes

1. RCS Class 1 major equipment supports are addressed in Table 3.5.2-1.

Table 3.5.2-14: Fire Barrier Commodity Group – Summary of Aging Management Evaluation

Table 3.5.2-14: Fire Barrier Commodity Group – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Fire barrier penetration seals	Fire barrier	Elastomer	Air – indoor uncontrolled	Hardening Loss of strength Shrinkage	Fire Protection (B.2.3.15)	VII.G.A-19	3.3-1, 057	A
Fire barrier penetration seals	Fire barrier	Stainless Steel	Air – indoor uncontrolled	Loss of material	Fire Protection (B.2.3.15)	III.B2.T-37c	3.5-1, 100	E, 2
Fire damper and louver frames	Fire barrier	Steel	Air – indoor uncontrolled	Loss of material Cracking Loss of strength Shrinkage	Fire Protection (B.2.3.15)	VII.G.A-789	3.3-1, 255	A
Fire damper and louver frames	Fire barrier	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.TP-3	3.5-1, 089	A
Fireproofing	Fire barrier	Cementitious	Air – indoor uncontrolled	Cracking Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-805	3.3-1, 268	A, 1
Fire stops and wraps	Fire barrier	Calcium Silicate Board	Air – indoor uncontrolled	Cracking Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-806	3.3-1, 269	A, 1
Fire stops and wraps	Fire barrier	Ceramic Fiber, Board, Mat	Air – indoor uncontrolled	Cracking Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-806	3.3-1, 269	A, 1

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

Plant Specific Notes

1. Consistent with SLR-ISG-Mechanical-2020-XX, “Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance”.
2. Stainless steel that is exposed to air – indoor uncontrolled during normal plant operation are inspected under the Fire Protection (B.2.3.15) AMP with the structural equivalent of the NUREG-2191 XI.M36, Externals Surfaces Monitoring of Mechanical Components AMP.

Table 3.5.2-15: Cranes, Hoists, and Lifting Devices – Summary of Aging Management Evaluation

Table 3.5.2-15: Cranes, Hoists, and Lifting Devices – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bridge and Trolley Framing, Crane Rails, Monorails, Lifting Devices	Structural support	Steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7.6, Fatigue of Cranes (Crane Cycle Limits)	VII.B.A-06	3.3-1, 001	A
Bridge and Trolley Framing	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.TP-3	3.5-1, 089	A
Bridge and Trolley Framing	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Inspection of Overhead Heavy Load Handling Systems	VII.B.A-07	3.3-1, 052	A
Crane Rails	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.TP-3	3.5-1, 089	A
Crane Rails	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Inspection of Overhead Heavy Load Handling Systems	VII.B.A-07	3.3-1, 052	A
Lifting Devices	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.TP-3	3.5-1, 089	A
Lifting Devices	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Inspection of Overhead Heavy Load Handling Systems	VII.B.A-07	3.3-1, 052	A
Monorails	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.TP-3	3.5-1, 089	A
Monorails	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Inspection of Overhead Heavy Load Handling Systems	VII.B.A-07	3.3-1, 052	A
Rail Hardware	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.1.TP-3	3.5-1, 089	A
Rail Hardware	Structural support	Steel	Air – indoor uncontrolled	Cracking Loss of material Loss of preload	Inspection of Overhead Heavy Load Handling Systems	VII.B.A-730	3.3-1, 199	A

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

3.6. AGING MANAGEMENT OF ELECTRICAL AND INSTRUMENTATION AND CONTROLS

3.6.1. Introduction

This section provides the results of the AMR for the electrical commodities identified in Table 2.5-2 of Section 2.5 as being subject to an AMR. The commodities addressed in this section include:

- Insulated cables and connections not included in the Environmental Qualification (10 CFR 50.49) Program[3]:
  - Cable connections (metallic parts) not subject to 10 CFR 50.49 EQ requirements
  - Insulated cables and connections not subject to 10 CFR 50.49 EQ requirements
  - Sensitive instrumentation circuits cables and connections not subject to 10 CFR 50.49 EQ requirements
  - Inaccessible and underground medium-voltage (2 kV to 35 kV) power cables (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) not subject to 10 CFR 50.49 EQ requirements
  - Inaccessible and underground instrumentation and control cables (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) not subject to 10 CFR 50.49 EQ requirements
  - Inaccessible and underground low-voltage (typical operating voltage of less than 1,000V, but no greater than 2 kV) power cables (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) not subject to 10 CFR 50.49 EQ requirements

[3] This commodity group is subdivided for technical clarity and proper identification of applicable aging effects consistent with NUREG-2191 guidance.

- Electrical and I&C penetration assemblies not subject to 10 CFR 50.49 EQ requirements
- Switchyard bus and connections
- Transmission conductors and connections
- High-voltage insulators
- Metal Enclosed Bus

Table 3.6-1, Summary of Aging Management Evaluations for Electrical Commodities, provides the AMRs and the programs evaluated in NUREG-2191 for electrical commodities. This table uses the format described in the introduction to Section 3. Links are provided to the program evaluations in Appendix B.

3.6.2. Results

Table 3.6.2-1, Electrical Commodities Summary of Aging Management Evaluation, presents the results of AMRs and the NUREG-2191 comparison for electrical commodities.

3.6.2.1. Materials, Environments, Aging Effects Requiring Management, and Aging Management Programs

The following sections list the materials, environments, aging effects requiring management, and aging management programs for electrical commodities subject to AMR. Programs are described in Appendix B. Further details are provided in Table 3.6.2-1.

Materials

Electrical commodities subject to AMR are constructed of the following materials.

- Aluminum
- Cement
- Copper
- Elastomer
- Galvanized metals
- Insulation material – various organic polymers
- Malleable Iron
- Porcelain
- Stainless steel
- Steel and steel alloys
- Various metals used for bus and electrical connections

Environment

Electrical commodities subject to AMR are exposed to the following environments.

- Adverse localized environment caused by heat, radiation, or moisture
- Adverse localized environment caused by significant moisture
- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects associated with electrical commodities require management.

- Elastomer loss of strength or change in material properties
- Increased resistance of connection
- Loss of material
- Reduced insulation resistance (IR)

Aging Management Programs

The following aging management programs will manage the effects of aging on electrical commodities.

- Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.37)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits (B.2.3.38)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.39)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.40)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.41)
- Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.43)
- Metal Enclosed Bus (B.2.3.42)
- High-Voltage Insulators (B.2.3.44)
- Boric Acid Corrosion (B.2.3.4)

3.6.2.2. AMR Results for Which Further Evaluation is recommended by the GALL Report

NUREG-2192 indicates that further evaluation is necessary for certain aging effects and programs identified in Section 3.6.2.2 of NUREG-2192. The following sections, numbered corresponding to the discussions in NUREG-2192, present the PBN evaluation of the areas requiring further evaluation. Programs are described in Appendix B. Italicized text is taken directly from NUREG-2192.

AMR Results for Which Further Evaluation Is Recommended by the Generic Aging Lessons Learned for Subsequent License Renewal Report

The basic acceptance criteria defined in Section 3.6.2.1 need to be applied first for all of the AMRs and AMPs reviewed as part of this section. In addition, if the GALL-SLR Report AMR item to which the SLRA AMR item is compared identifies that "further evaluation is recommended," then additional criteria apply as identified by the GALL-SLR Report for each of the following aging effect/aging mechanism combinations. Refer to Table 3.6-1, comparing the "Further Evaluation Recommended" and the "GALL-SLR Item" column, for the AMR items that reference the following subsections.

3.6.2.2.1 *Electrical Equipment Subject to Environmental Qualification*

Environmental qualification is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed separately in Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment," of this SRP-SLR.

Electrical equipment environmental qualification (EQ) analyses are TLAAs as defined in 10 CFR 54.3. TLAAs are evaluated in accordance with 10 CFR 54.21(c) and addressed in Section 4.4. EQ components are subject to replacement based on a qualified life, and therefore, are not subject to AMR.

3.6.2.2.2 *Reduced Insulation Resistance Due to Age Degradation of Cable Bus Arrangements Caused by Intrusion of Moisture, Dust, Industrial Pollution, Rain, Ice, Photolysis, Ohmic Heating and Loss of Strength of Support Structures and Louvers of Cable Bus Arrangements Due to General Corrosion and Exposure to Air Outdoor*

Reduced insulation resistance due to age degradation of cable bus caused by intrusion of moisture, dust, industrial pollution, rain, ice, photolysis (for ultraviolet sensitive material only), ohmic heating and loss of strength of support structures, covers or louvers of cable bus arrangements due to general corrosion or exposure to air outdoor could occur in cable bus assemblies. Cable bus is a variation of metal enclosed bus (MEB) which is similar in construction to an MEB, but instead of segregated or nonsegregated electrical buses, cable bus is comprised of a fully enclosed metal enclosure that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus may omit the top cover or use a louvered top cover and enclosure. Both the cable bus and enclosures are not sealed against intrusion of dust, industrial pollution, moisture, *rain, and ice and therefore may introduce debris into the internal cable bus assembly.*

Consequently, cable bus construction and arrangements are such that it may not readily fall under a specific GALL-SLR Report AMP (e.g., GALL-SLR Report AMP XI.E1 and AMP XI.E4).GALL-SLR Report AMP XI.E1 calls for a visual inspection of accessible insulated cables and connections subject to an adverse localized environment which may not be applicable to cable bus due to inaccessibility or applicability of the aging mechanisms and effects. GALL-SLR Report AMP XI.E4 includes tests and inspections of the internal and external portions of the MEB. The MEB internal and external inspections and tests may not be applicable to cable bus aging mechanisms and effects. Therefore, the GALL-SLR Report recommends cable bus aging mechanisms and effects be evaluated as a plant-specific further evaluation. The evaluation includes associated AMPs: AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," and AMP XI.S6, "Structures Monitoring." Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP-SLR).

The discussion in NUREG-2192 addresses aging effects on cable bus. Cable bus is a variation of metal enclosed bus (MEB) which is similar in construction to a MEB, but instead of segregated or non-segregated electrical buses, cable bus is comprised of a metallic cable tray enclosure that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus is not utilized at PBN, and therefore, NUREG-2192 aging effects are not applicable. Section 2.5.1.3 contains additional information on cable bus.

3.6.2.2.3 *Loss of Material Due to Wind-Induced Abrasion, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload for Transmission Conductors, Switchyard Bus, and Connections*

Loss of material due to wind-induced abrasion, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload could occur in transmission conductors and connections, and in switchyard bus and connections. The GALL-SLR Report recommends further evaluation of a plant specific AMP to demonstrate that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of the SRP-SLR).

Transmission conductors are uninsulated, stranded electrical cables used in switchyards and switching stations to connect two or more elements of an electrical power circuit, such as active disconnect switches, power circuit breakers, and transformers and passive switchyard bus. The transmission conductor commodity group includes the associated fastening hardware but excludes the high-voltage insulators. Major active equipment assemblies include their associated transmission conductor terminations.

Transmission conductors are subject to AMR if they are necessary for recovery of offsite power following an SBO event. The PBN power path for restoration of offsite power following an SBO event utilizes short (jumper) connections of 2156 MCM aluminum conductor steel reinforced (ACSR) to connect the Unit 1 and Unit 2 345 kV circuit switchers to the high-voltage station auxiliary transformers on each unit. The Unit 1 and Unit 2 circuit switchers are the last components in the connection to offsite power controlled by PBN operators and demarcate the SBO switchyard boundary for SLR. Other PBN transmission conductors are not subject to AMR since they do not perform or support SLR intended functions.

Switchyard bus is the uninsulated, unenclosed, rigid electrical conductor or pipe used in switchyards and switching stations to connect two or more elements of an electrical power circuit, such as active disconnect switches and passive transmission conductors. Switchyard bus includes the hardware used to secure the bus to high-voltage insulators. Switchyard bus is subject to AMR if it is necessary for recovery of offsite power following an SBO event. At PBN, switchyard bus from the 345 kV circuit switchers to the high-voltage station auxiliary transformers on each unit support SBO recovery. Other switchyard bus is not subject to AMR since it does not perform or support SLR intended functions.

- <u>Loss of Material (Wear)</u>

Wind loading can cause transmission conductor vibration, or sway. At PBN, connections between the 345 kV circuit switchers and the high-voltage station auxiliary transformer are made by short transmission conductor jumper cables. Wind loading that can cause a transmission line and insulators to vibrate or sway are not applicable to the short transmission conductor jumper cables utilized at PBN. As a result, loss of material (wear) and fatigue that could be caused by transmission conductor vibration or sway are not aging effects requiring management because they are precluded by the length of the PBN transmission conductor jumper cables. A review of industry OE and NRC generic communications related to the aging of transmission conductors confirmed that no additional aging effects exist beyond those previously identified. A review of plant-specific OE did not identify any unique aging effects for transmission conductors.

Switchyard bus is connected to active equipment by short sections of flexible conductors. The rigid bus does not vibrate because it is supported by station post insulators and ultimately by static, structural components such as concrete footings and structural steel. The flexible conductors dampen the minor vibrations associated with the active switchyard components to the switchyard bus. As a result, loss of material (wear) caused by switchyard bus vibration is not an aging effect requiring management because it is precluded by design.

Therefore, loss of material due to wear of transmission conductors and switchyard bus is not an aging effect requiring management at PBN.

- <u>Loss of Conductor Strength (Corrosion)</u>

This aging effect applies to aluminum conductor steel reinforced (ACSR) transmission conductors. In-scope transmission conductors at PBN are limited to the short jumper connections of 2156 MCM ACSR cable between the Unit 1 and Unit 2 345 kV circuit switchers and each unit's high-voltage station auxiliary transformer used for recovery of offsite power following an SBO event. The most prevalent mechanism contributing to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR transmission conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion in ACSR conductors is a very slow-acting aging mechanism with the corrosion rate depending largely on air quality. Air quality factors include suspended particle chemistry, sulfur dioxide (SO_2) concentration, precipitation, fog chemistry, and meteorological conditions. Air quality in rural areas, such as the area surrounding PBN, generally contains low concentrations of suspended particles and SO_2, which minimizes the corrosion rate. There are no major industries within the immediate vicinity of PBN. The site is in the town of Two Creeks in the northeast corner of Manitowoc County, Wisconsin, on the west shore of Lake Michigan about 30 miles southeast of the center of the city of Green Bay, and 90 miles NNE of Milwaukee. Manitowoc County and adjacent counties of Kewaunee, Brown, Calumet, and Sheboygan are predominantly rural. Agricultural pursuits account for approximately 90 percent of the total county acreage. The region within a radius of 5 miles of the site is presently devoted exclusively to agriculture. Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion.

There is set percentage of composite conductor strength established at which a transmission conductor is replaced. As illustrated below, there is ample strength margin to maintain the transmission conductor intended function through the SPEO.

The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind and temperature. These requirements are reviewed concerning the specific conductors included in the AMR. The conductors with the smallest ultimate strength margin (4/0 ACSR) will be used as an illustration.

The ultimate strength and the NESC heavy load tension requirements of 4/0 ACSR are 8350 lbs. and 2761 lbs. respectively. The margin between the NESC heavy load and the ultimate strength is 5589 lb.; i.e., there is a 67 percent of ultimate strength margin. The Ontario Hydroelectric study showed a 30 percent loss of composite conductor strength in an 80-year-old conductor. In the case of the 4/0 ACSR transmission conductors, a 30 percent loss of ultimate strength would mean that there would still be a 37 percent ultimate strength margin between what is required by the NESC and the actual conductor strength.

The 4/0 ACSR conductor has the lowest initial design margin of transmission conductors included in this review. This illustrates with reasonable assurance that transmission conductors will have ample strength through the SPEO. Also, it should be noted, the ACSR transmission conductor in the Ontario Hydroelectric study was an 80-year-old specimen whereas the PBN transmission conductor jumper cables were recently installed and are less than 2-years old. This illustrates with reasonable assurance that transmission conductors will have ample strength through the SPEO. A review of industry OE and NRC generic communications related to the aging of transmission conductors confirmed that no additional aging effects exist beyond those previously identified. A review of plant-specific OE did not identify any unique aging effects for transmission conductors.

Therefore, loss of conductor strength is not an aging effect requiring management for transmission conductors at PBN.

Increased Resistance of Connection (Corrosion)

Increased connection resistance due to surface oxidation is an applicable aging effect, but it is not significant enough to cause a loss of intended function. The aluminum, steel, and steel alloy components in the PBN switchyard are exposed to precipitation, but these components do not experience any appreciable aging effects in this environment, except for minor oxidation, which does not impact the ability of the connections to perform or support their SLR intended function. At PBN, switchyard connection surfaces are coated with an antioxidant compound (i.e., a grease-type sealant) prior to tightening the connection to prevent the formation of oxides on the metal surface and to prevent moisture from entering the connections, thus minimizing the potential for corrosion. Based on site-specific and industry wide operating experience, this method of installation has proven to provide a corrosion-resistant low electrical resistance connection. In addition, PBN periodically performs infrared inspections of the 345 kV switchyard connections to verify the integrity of the connections. The infrared inspections of the 345 kV switchyard connections verify the effectiveness of the connection design and site installation practices. These inspections and the absence of plant specific OE verifies that this aging effect is not significant for PBN.

Therefore, increased connection resistance due to general corrosion resulting from oxidation of switchyard connection metal surfaces is not an aging effect requiring management at PBN.

Increased Resistance of Connection (Loss of Preload)

Increased connection resistance due to loss of pre-load (torque relaxation) for switchyard connections is not an aging effect requiring management. The Electric Power Research Institute (EPRI) license renewal tools do not list loss of pre-load as an applicable aging mechanism. The design of transmission conductor and switchyard bus bolted connections precludes torque relaxation as confirmed by plant specific OE. A plant-specific review of OE did not identify any failures of switchyard connections. The design of switchyard bolted connections includes Belleville washers and an anti-oxidant compound (i.e., a grease-type sealant) to preclude connection degradation. The type of bolting plate and the use of Belleville washers is the industry standard to preclude torque relaxation. This design configuration, combined with the proper sizing of mounting hardware, eliminates the need to consider this aging mechanism. Therefore, increased connection resistance due to loss of pre-load on switchyard connections is not an aging effect requiring management.

For bolted connections between transmission conductors and switchyard bus, in-scope transmission conductors at PBN are limited to the short jumper cable connections between the 345 kV circuit switchers and each unit's high-voltage station auxiliary transformer used for recovery of offsite power following an SBO event. Routine inspections of the PBN 345 kV switchyard and startup transformers include performing periodic infrared inspections of this power path to verify the integrity of the connections. These inspections and the absence of plant specific OE demonstrates that this aging effect is not significant for PBN.

Therefore, increased connection resistance due to loss of pre-load of transmission conductor and switchyard bus connections is not an aging effect requiring management for PBN.

There are no applicable aging effects that could cause a loss of the intended function of the transmission conductor connections and switchyard bus connections for the SPEO. Therefore, there are no aging effects requiring management for PBN transmission conductors and switchyard bus connections.

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in BTP IQMB-1 (Appendix A.2 of the SRP-SLR).

Quality Assurance provisions applicable to SLR for PBN are discussed in Appendix B.

3.6.2.2.5 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs.

The Operating Experience process and acceptance criteria are described in Appendix B.

3.6.2.3. Time-Limited Aging Analysis

The TLAAs identified below are associated with the electrical commodities:

- Section 4.4, Environmental Qualification (EQ) of Electrical Equipment

3.6.3. Conclusion

Electrical commodities that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.21(a)(1). Aging management programs selected to manage aging effects for electrical commodities are identified in Section 3.6.2.1 and in the following tables. A description of aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be effectively managed.

Based on the demonstrations provided in Appendix B, the effects of aging associated with electrical commodities will be managed such that the intended functions will be maintained consistent with the CLB during the SPEO.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 001	Electrical equipment subject to 10 CFR 50.49 EQ requirements composed of various polymeric and metallic materials in plant areas subject to a harsh environment (i.e., loss of coolant accident (LOCA), high energy line break (HELB), or post LOCA environment or; An Adverse localized environment for the most limiting qualified condition for temperature, radiation, or moisture for the component material (e.g., cable or connection insulation).	Various aging effects due to various mechanisms in accordance with 10 CFR 50.49	EQ is a time-limited aging analysis (TLAA) to be evaluated for the SPEO. See the Standard Review Plan, Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)(i) and (ii). See Chapter X.E1, "Environmental Qualification (EQ) of Electric Components," of this report for meeting the requirements of 10 CFR 54.21(c)(1)(i)-(iii).	Yes, TLAA (SRP-SLR Section 3.6.2.2.1)	Consistent with NUREG-2191. EQ equipment is not subject to AMR because the equipment is subject to replacement based on a qualified life. EQ analyses are evaluated as TLAAs in Section 4.4. See Section 3.6.2.2.1 for further evaluation
3.6-1, 002	High-voltage insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air – outdoor	Loss of material due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind	AMP XI.E7, "High-Voltage Insulators"	No	Consistent with NUREG-2191. The High-Voltage Insulators (B.2.3.44) AMP will manage these aging effects.
3.6-1, 003	High-voltage insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air – outdoor	Reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume or industrial effluent contamination	AMP XI.E7, "High-Voltage Insulators"	No	Consistent with NUREG-2191. The High-Voltage Insulators (B.2.3.44) AMP will manage these aging effects.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 004	Transmission conductors composed of aluminum; steel exposed to air – outdoor	Loss of conductor strength due to corrosion	A plant-specific aging management program is to be evaluated for ACSR	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to PBN. See Section 3.6.2.2.3 for further evaluation.
3.6-1, 005	Transmission connectors composed of aluminum; steel exposed to air – outdoor	Increased resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to PBN. See Section 3.6.2.2.3 for further evaluation.
3.6-1, 006	Switchyard bus and connections composed of aluminum; copper; bronze; stainless steel; galvanized steel exposed to air – outdoor	Loss of material due to wind induced abrasion; Increased resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to PBN. See Section 3.6.2.2.3 for further evaluation.
3.6-1, 007	Transmission conductors composed of aluminum; steel exposed to air – outdoor	Loss of material due to wind-induced abrasion	A plant-specific aging management program is to be evaluated for ACAR and ACSR	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to PBN. See Section 3.6.2.2.3 for further evaluation.
3.6-1, 008	Electrical insulation for electrical cables and connections (including terminal blocks, etc.) composed of various organic polymers (e.g., EPR (ethylene propylene rubber), SR (silicone rubber), EPDM (ethylene propylene diene monomers), XLPE (cross-linked polyethylene)) exposed to an adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Consistent with NUREG-2191. The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.37) AMP will manage the effects of aging. This AMP includes inspection of non-EQ electrical and I&C penetration cables and connections. PBN EQ electrical and I&C penetration assemblies are covered under the EQ program.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 009	Electrical insulation for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance (IR) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to an adverse localized environment caused by heat, radiation, or moisture	Reduced insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E2, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"	No	Consistent with NUREG-2191. The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits (B.2.3.38) AMP will manage these aging effects. This AMP includes review of calibration results or surveillance findings for instrumentation circuits.
3.6-1, 010	Electrical conductor insulation for inaccessible power, instrumentation, and control cables (e.g., installed in duct bank, buried conduit or direct buried) composed of various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield exposed to an adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength due to significant moisture	AMP XI.E3A, "Electrical Insulation for Inaccessible Medium- Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," AMP XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," or AMP XI.E3C, "Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements"	No	Consistent with NUREG-2191. The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.39) XI.E3A AMP, the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.40) XI.E3B AMP, or the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.41) XI.E3C AMP will manage these aging effects. AMPs include inspection of manholes and de-watering activities as required.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 011	Metal enclosed bus: enclosure assemblies composed of elastomers exposed to air – indoor controlled or uncontrolled, air – outdoor	Surface cracking, crazing, scuffing, dimensional change (e.g. "ballooning" and "necking"), shrinkage, discoloration, hardening, loss of strength due to elastomer degradation	AMP XI.E4, "Metal Enclosed Bus" or AMP XI.S6, "Structures Monitoring" AMP	No	Consistent with NUREG-2191. The Metal Enclosed Bus (B.2.3.42) AMP or Structures Monitoring (B.2.3.34) AMP will manage these aging effects.
3.6-1, 012	Metal enclosed bus: bus/connections composed of various metals used for electrical bus and connections exposed to air – indoor controlled or uncontrolled, air – outdoor	Increased electrical resistance of connection due to the loosening of bolts caused by thermal cycling and ohmic heating	AMP XI.E4, "Metal Enclosed Bus"	No	Consistent with NUREG-2191. The Metal Enclosed Bus (B.2.3.42) AMP will manage these aging effects.
3.6-1, 013	Metal enclosed bus: electrical insulation; insulators composed of porcelain; xenoy; thermo-plastic organic polymers exposed to air – indoor controlled or uncontrolled, air – outdoor	Reduced electrical insulation resistance due to thermal / thermoxidative degradation of organics/thermoplastics radiation-induced oxidation, moisture/debris intrusion, and ohmic heating	AMP XI.E4, "Metal Enclosed Bus"	No	Consistent with NUREG-2191. The Metal Enclosed Bus (B.2.3.42) AMP will manage these aging effects.
3.6-1, 014	Metal enclosed bus: external surface of enclosure assemblies composed of steel exposed to air – indoor uncontrolled, air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.E4, "Metal Enclosed Bus" or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Metal Enclosed Bus (B.2.3.42) AMP or Structures Monitoring (B.2.3.34) AMP will manage these aging effects.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 015	Metal enclosed bus: external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air – outdoor	Loss of material due to pitting, crevice corrosion	AMP XI.E4, "Metal Enclosed Bus" or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Metal Enclosed Bus (B.2.3.42) AMP or Structures Monitoring (B.2.3.34) AMP will manage these aging effects.
3.6-1, 016	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor, uncontrolled	Increased electrical resistance of connection due to chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection due to chemical contamination, corrosion and oxidation do not apply)	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms and effects due to chemical contamination, corrosion, and oxidation.	No	Not applicable. The electrical screening process determined that there are not any safety related fuses, or nonsafety-related fuses which support a system level intended function, that are not part of an active component such as switchgear, power supplies, power inverters, battery chargers, load centers, and circuit boards. Therefore, fuse holders with metallic clamps at PBN are not subject to AMR.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 017	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor, controlled or uncontrolled	Increased electrical resistance of connection due to fatigue from ohmic heating, thermal cycling, electrical transients	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue due to ohmic heating, thermal cycling, electrical transients.	No	Not applicable. The electrical screening process determined that there are not any safety related fuses, or nonsafety-related fuses which support a system level intended function, that are not part of an active component such as switchgear, power supplies, power inverters, battery chargers, load centers, and circuit boards. Therefore, fuse holders with metallic clamps at PBN are not subject to AMR.
3.6-1, 018	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor, controlled or uncontrolled	Increased electrical resistance of connection due to fatigue caused by frequent fuse removal/manipulation or vibration	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue caused by frequent fuse removal/manipulation or vibration.	No	Not applicable. The electrical screening process determined that there are not any safety related fuses, or nonsafety-related fuses which support a system level intended function, that are not part of an active component such as switchgear, power supplies, power inverters, battery chargers, load centers, and circuit boards. Therefore, fuse holders with metallic clamps at PBN are not subject to AMR.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 019	Cable connections (metallic parts) composed of various metals used for electrical contacts exposed to air – indoor controlled or uncontrolled, air – outdoor	Increased electrical resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	AMP XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	No	Consistent with NUREG-2191. The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements (B.2.3.43) AMP will manage the effects of aging.
3.6-1, 020	Electrical connector contacts for electrical connectors composed of various metals used for electrical contacts exposed to air with borated water leakage	Increased electrical resistance of connection due to corrosion of connector contact surfaces caused by intrusion of borated water	AMP XI.M10, “Boric Acid Corrosion”	No	Consistent with NUREG-2191. The Boric Acid Corrosion (B.2.3.4) AMP will manage the effects of aging.
3.6-1, 021	Transmission conductors composed of aluminum exposed to air – outdoor	Loss of conductor strength due to corrosion	None – for ACAR and all Aluminum Conductor (AAC)	No	NUREG-2191 aging effects are not applicable to PBN. See Section 3.6.2.2.3 for further evaluation.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 022	Fuse holders (not part of active equipment): insulation material composed of electrical insulation material: bakelite; phenolic melamine or ceramic; molded polycarbonate, and other, exposed to air – indoor controlled or uncontrolled	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms	No	Not applicable. The electrical screening process determined that there are not any safety related fuses, or nonsafety-related fuses which support a system level intended function, that are not part of an active component such as switchgear, power supplies, power inverters, battery chargers, load centers, and circuit boards. Therefore, fuse holders with metallic clamps at PBN are not subject to AMR.
3.6-1, 023	Metal enclosed bus: external surface of enclosure assemblies. Galvanized steel; aluminum. air – indoor controlled or uncontrolled	None	None	No	Consistent with NUREG-2191.
3.6-1, 024	Metal enclosed bus: external surface of enclosure assemblies. Steel air – indoor controlled	None	None	No	Consistent with NUREG-2191.
3.6-1, 027	Cable bus: external surface of enclosure assemblies galvanized steel; aluminum; air – indoor controlled or uncontrolled	None	None	No	Not applicable. Cable bus is not utilized at PBN.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6-1, 029	Cable bus: electrical insulation; insulators – exposed to air – indoor controlled or uncontrolled, air – outdoor	Reduced electrical insulation resistance due to degradation caused thermal/ thermoxidative degradation of organics and photolysis (UV sensitive materials only) of organics, moisture/debris intrusion and ohmic heating	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Not applicable. Cable bus is not utilized at PBN.
3.6-1, 030	Cable bus: external surface of enclosure assemblies composed of steel exposed to air – indoor uncontrolled or air – outdoor	Loss of material due to general, pitting, crevice corrosion	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Not applicable. Cable bus is not utilized at PBN.
3.6-1, 031	Cable bus external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Not applicable. Cable bus is not utilized at PBN.
3.6-1, 032	Cable bus: external surface of enclosure assemblies: composed of steel; air – indoor controlled	None	None	No	Not applicable. Cable bus is not utilized at PBN.

Table 3.6.2-1: Electrical Commodities – Summary of Aging Management Evaluation

Table 3.6.2-1: Electrical Commodities – Summary of Aging Management Evaluation								
Structure and/or Component	**Component Intended Function**	**Material**	**Environment**	**Aging Effect / Mechanism**	**Aging Management Program (AMP) / TLAA**	**NUREG-2191 Item**	**SRP Item**	**Notes**
Cable connections (metallic parts)	Electrical Continuity	Various metals used for electrical contacts	Air – indoor controlled or uncontrolled, Air – outdoor	Increased electrical resistance of connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.43)	VI.A.LP-30	3.6-1, 019	A
Electrical conductor insulation for inaccessible instrumentation and control cables (e.g., installed in duct bank, buried conduit or direct buried)	Insulate (electrical)	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket / insulation shield	Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.40)	VI.A.LP-35b	3.6-1, 010	A

Table 3.6.2-1: Electrical Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect / Mechanism	Aging Management Program (AMP) / TLAA	NUREG-2191 Item	SRP Item	Notes
Electrical conductor insulation for inaccessible low-voltage cables – typical operating voltage of < 1 kV but no greater than 2 kV (e.g., installed in duct bank, buried conduit or direct buried)	Insulate (electrical)	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket / insulation shield	Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.41)	VI.A.LP-35c	3.6-1, 010	A
Electrical conductor insulation for inaccessible medium-voltage cables – typical operating range of 2 kV to 35 kV (e.g., installed in duct bank, buried conduit or direct buried)	Insulate (electrical)	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket / insulation shield	Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.39)	VI.A.LP-35a	3.6-1, 010	A
Electrical connector contacts for electrical connectors	Electrical Continuity	Various metals used for electrical contacts	Air with borated water leakage	Increased electrical resistance of connection	Boric Acid Corrosion (B.2.3.4)	VI.A.LP-36	3.6-1, 020	A

Table 3.6.2-1: Electrical Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect / Mechanism	Aging Management Program (AMP) / TLAA	NUREG-2191 Item	SRP Item	Notes
Electrical insulation for electrical cables and connections (including terminal blocks, etc.)	Insulate (electrical)	Various organic polymers (e.g., EPR, SR, EPDM, XLPE)	Adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.37)	VI.A.LP-33	3.6-1, 008	A
Electrical insulation for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor electrical insulation resistance (IR)	Insulate (electrical)	Various organic polymers (e.g., EPR, SR, EPDM, XLPE)	Adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.3.38)	VI.A.LP-34	3.6-1, 009	A
High-voltage electrical insulators	Insulate (electrical)	Porcelain; malleable iron; aluminum; galvanized steel; cement	Air – outdoor	Loss of Material	High-Voltage Insulators (B.2.3.44)	VI.A.LP-32	3.6-1, 002	A

Table 3.6.2-1: Electrical Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect / Mechanism	Aging Management Program (AMP) / TLAA	NUREG-2191 Item	SRP Item	Notes
High-voltage electrical insulators	Insulate (electrical)	Porcelain; malleable iron; aluminum; galvanized steel; cement	Air – outdoor	Reduced electrical insulation resistance	High-Voltage Insulators (B.2.3.44)	VI.A.LP-28	3.6-1, 003	A
Switchyard bus and connections	Electrical Continuity	Aluminum; copper; bronze; stainless steel; galvanized steel	Air – outdoor	None	None	VI.A.LP-39	3.6-1, 006	I
Transmission conductors	Electrical Continuity	Aluminum	Air – outdoor	None	None	VI.A.LP-46	3.6-1, 021	I
Transmission conductors	Electrical Continuity	Aluminum; steel	Air – outdoor	None	None	VI.A.LP-48	3.6-1, 005	I
Transmission conductors	Electrical Continuity	Aluminum; steel	Air – outdoor	None	None	VI.A.LP-38	3.6-1, 004	I
Transmission conductors	Electrical Continuity	Aluminum; steel	Air – outdoor	None	None	VI.A.LP-47	3.6-1, 007	I

Table 3.6.2-1: Electrical Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect / Mechanism	Aging Management Program (AMP) / TLAA	NUREG-2191 Item	SRP Item	Notes
Electrical equipment subject to 10 CFR 50.49 EQ requirements	Insulate (electrical)	Various polymeric materials	Areas of the plant that could be subject to harsh environmental effects of a loss of coolant accident (LOCA), high energy line break, or post LOCA environment Adverse localized environment (e.g., temperature, radiation, or moisture)	Various aging effects due to various mechanisms in accordance with 10 CFR 50.49	Environmental Qualification of Electric Equipment (B.2.2.4)	VI.B.L-05	3.6-1, 001	A
Electrical equipment subject to 10 CFR 50.49 EQ requirements	Electrical Continuity	Various metallic materials	Areas of the plant that could be subject to harsh environmental effects of a loss of coolant accident (LOCA), high energy line break, or post LOCA environment Adverse localized environment (e.g., temperature, radiation, or moisture)	Various aging effects due to various mechanisms in accordance with 10 CFR 50.49	Environmental Qualification of Electric Equipment (B.2.2.4)	VI.B.L-05	3.6-1, 001	A

Table 3.6.2-1: Electrical Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect / Mechanism	Aging Management Program (AMP) / TLAA	NUREG-2191 Item	SRP Item	Notes
Metal enclosed bus: bus/connections	Electrical Continuity	Various metals used for electrical bus and connections	Air – indoor, controlled or uncontrolled or Air – outdoor	Increased electrical resistance of connection	Metal Enclosed Bus (B.2.3.42)	VI.A.LP-25	3.6-1, 012	A
Metal enclosed bus: enclosure assemblies	Electrical Continuity	Elastomers	Air – indoor, controlled or uncontrolled or Air – outdoor	Change in material properties	Metal Enclosed Bus (B.2.3.42) or Structures Monitoring (B.2.3.34)	VI.A.LP-29	3.6-1, 011	A
Metal enclosed bus: external surface of enclosure assemblies	Electrical Continuity	Galvanized steel; aluminum	Air – indoor, controlled or uncontrolled	None	None	VI.A.LP-41	3.6-1, 023	A
Metal enclosed bus: external surface of enclosure assemblies	Electrical Continuity	Galvanized steel; aluminum	Air – outdoor	Loss of material	Metal Enclosed Bus (B.2.3.42) or Structures Monitoring (B.2.3.34)	VI.A.LP-42	3.6-1, 015	A
Metal enclosed bus: external surface of enclosure assemblies	Electrical Continuity	Steel	Air – indoor, controlled	None	None	VI.A.LP-44	3.6-1, 024	A
Metal enclosed bus: external surface of enclosure assemblies	Electrical Continuity	Steel	Air – indoor, uncontrolled or Air – outdoor	Loss of material	Metal Enclosed Bus (B.2.3.42) or Structures Monitoring (B.2.3.34)	VI.A.LP-43	3.6-1, 014	A

Table 3.6.2-1: Electrical Commodities – Summary of Aging Management Evaluation								
Structure and/or Component	**Component Intended Function**	**Material**	**Environment**	**Aging Effect / Mechanism**	**Aging Management Program (AMP) / TLAA**	**NUREG-2191 Item**	**SRP Item**	**Notes**
Metal enclosed bus: insulation; insulators	Insulate (electrical)	Porcelain; xenoy; thermo-plastic organic polymers	Air – indoor, controlled or uncontrolled or Air – outdoor	Reduced electrical insulation resistance	Metal Enclosed Bus (B.2.3.42)	VI.A.LP-26	3.6-1, 013	A

Generic Notes

A) Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

I) Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

Plant Specific Notes

None

4.0 TIME-LIMITED AGING ANALYSES (TLAAs)

This section presents descriptions of the Time-Limited Aging Analyses (TLAAs) and exemptions for PBN Units 1 and 2 in accordance with 10 CFR 54.3(a) and 10 CFR 54.21(c). Section 4 is divided into Sections 4.1 through 4.7. A number of non-proprietary and proprietary reference documents have been included in Enclosures 4 and 5, respectively, to NEPB letter NRC 2020-0032, and are cited, where applicable, throughout this section.

Section 4.1 provides the 10 CFR Part 54 definition and requirements for TLAAs and summarizes the process used for identifying and evaluating TLAAs and exemptions. This section also presents the summary of the results of the PBN TLAAs. Subsequent sections describe the evaluation of each TLAA within the following categories.

- Section 4.2, Reactor Vessel Neutron Embrittlement
- Section 4.3, Metal Fatigue
- Section 4.4, Environmental Qualification (EQ) of Electric Equipment
- Section 4.5, Concrete Containment Tendon Prestress
- Section 4.6, Containment Liner Plate, Metal Containments, and Penetrations Fatigue
- Section 4.7, Other Plant-Specific TLAA

4.1. IDENTIFICATION OF TIME-LIMITED AGING ANALYSES

10 CFR 54.21(c) requires an evaluation of TLAAs be provided as part of the application for a renewed license. Time-limited aging analyses are defined in 10 CFR 54.3 as those licensee calculations and analyses that:

(1) Involve systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a);
(2) Consider the effects of aging;
(3) Involve time-limited assumptions defined by the current operating term;
(4) Were determined to be relevant by the licensee in making a safety determination;
(5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in 10 CFR 54.4(b); and
(6) Are contained or incorporated by reference in the CLB.

4.1.1. Time-Limited Aging Analyses Identification Process

A list of potential TLAAs was compiled from regulatory and industry sources, including:

- NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report"
- NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants"
- NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal"
- 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"
- Prior license renewal applications
- Plant-specific document reviews

Keyword searches were performed on the CLB documentation to determine whether these potential TLAAs exist in the CLB. The keyword search was also used to identify additional potential plant-specific TLAAs. The CLB search included:

- Updated Final Safety Analysis Report (UFSAR)
- Technical Specifications and Bases
- Technical Requirements Manual
- NRC Safety Evaluation Reports (SERs) for the original operating license
- Subsequent NRC Safety Evaluations (SEs)
- Docketed licensing correspondence between previous PBN owners/operators, NextEra Energy, and NRC

The potential TLAAs were then reviewed against the TLAA definition in 10 CFR 54.3(a). The review considered information in the CLB documents and from source documents for the potential TLAAs such as:

- Vendor, NRC-sponsored, and licensee topical reports
- Calculations
- Code stress reports or code design reports
- Drawings
- Specifications

Potential TLAAs that met all six elements of the 10 CFR 54.3(a) definition were identified as TLAAs that required evaluation for the subsequent period of extended operation.

4.1.2. Evaluation of PBN Time-Limited Aging Analyses

Each part of Section 4 evaluates one or more related TLAAs. Information is provided using the following definitions:

TLAA Description:

A description of the CLB analysis that has been identified as a TLAA, including a description of the aging effect evaluated, the time-limited variable used in the analysis, and its basis.

TLAA Evaluation:

An evaluation of the TLAA for the SPEO. This section provides the information associated with 80 years of operation for comparison with the information used in the TLAA that considered 60 years of operation. This evaluation provides the basis for the TLAA disposition, which will be one of the three disposition options specified in 10 CFR 54.21(c)(1).

TLAA Disposition:

Each TLAA is demonstrated as acceptable in accordance with one of the three options from 10 CFR 54.21(c)(1) specified below in Section 4.1.3.

4.1.3. Acceptance Criteria

10 CFR 54.21, Contents of application – technical information, requires that a subsequent license renewal application contain the following information:

(c) An evaluation of time-limited aging analyses.

1. A list of time-limited aging analyses, as defined in §54.3, must be provided. The applicant shall demonstrate that:

   (i) The analyses remain valid for the SPEO;
   (ii) The analyses have been projected to the end of the SPEO; or
   (iii) The effects of aging on the intended function(s) will be adequately managed for the SPEO.

One of these three methods were used to disposition each TLAA identified for PBN. The disposition methods used are described in each TLAA evaluation section.

4.1.4. Identification and Evaluation of Exemptions

10 CFR 54.21(c)(2) states: A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on TLAAs as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the SPEO.

A search of docketed licensing correspondence, the operating license, and the Updated Final Safety Analysis Report (UFSAR) identified the active exemptions currently in effect pursuant to 10 CFR 50.12. These exemptions were then reviewed to determine whether the exemption was based on a TLAA. There were no exemptions to 10 CFR 50.12 identified for PBN Units 1 and 2 that are currently in effect that are based upon a TLAA.

4.1.5. Summary of Results

Table 4.1.5-1, Review of Generic TLAAs Listed in NUREG-2192 and Table 4.1.5-2, Review of Plant-Specific TLAAs Listed in NUREG-2192, list the example TLAAs provided in NUREG-2192 and specify whether they have been identified as TLAAs for PBN. The section(s) where the TLAA(s) are evaluated are identified. Those examples with a “Yes” entry apply. Those examples with a “No” entry do not apply and no TLAA was identified for these categories either because they are associated with design features not employed or because no analysis was identified that meets all six elements of the TLAA definition in 10 CFR 54.3(a).

Sections 4.2 through 4.7 of this report describe the evaluations of six general categories of TLAAs. The TLAA categories and associated analyses are listed in Table 4.1.5.-3, Summary of Results - PBN TLAAs. The TLAA categories are presented in the order in which they appear in Sections 4.2 through 4.7 of NUREG-2192. The table entries also indicate the disposition method used in evaluating the TLAA and include a reference to the applicable report section where the TLAA is evaluated for the SPEO.

Table 4.1.5-1
Review of Generic TLAAs Listed in NUREG-2192, Table 4.1-2

NUREG-2192, Table 4.1-2 - Generic TLAAs		Applies to PBN	SLRA Section
Reactor Vessel Neutron Embrittlement	Neutron Fluence	Yes	4.2.1
	Pressurized Thermal Shock (PWRs Only)	Yes	4.2.2
	Upper Shelf Energy (PWRs and BWRs)	Yes	4.2.3
	Pressure Temperature (P-T) Limits (PWRs and BWRs)	Yes	4.2.4
	Low Temperature Overpressure Protection System Setpoints (PWRs Only)	Yes	4.2.5
	Ductility Reduction Evaluation for Reactor Internals (B&W designed PWRs only)	No	N/A
	RV Circumferential Weld Relief-Probability of Failure and Mean Adjusted Reference Temperature Analysis for the RV Circumferential Welds (BWRs only)	No	N/A
	Reactor Vessel Axial Weld Probability of Failure and Mean Adjusted Reference Temperature Analysis (BWRs only)	No	N/A
Metal Fatigue	Metal Fatigue of Class 1 Components	Yes	4.3.1
	Metal Fatigue of Non-Class 1 Components	Yes	4.3.3
	Environmentally-Assisted Fatigue	Yes	4.3.4
	High-Energy Line Break Analyses	No (Note 1)	N/A
	Cycle-dependent Fracture Mechanics or Flaw Evaluations	Yes (Note 2)	4.7.3
	Cycle-dependent Fatigue Waivers	Yes	4.3.2

Table 4.1.5-1
Review of Generic TLAAs Listed in NUREG-2192, Table 4.1-2

NUREG-2192, Table 4.1-2 - Generic TLAAs	Applies to PBN	SLRA Section
Environmental Qualification of Electric Equipment	Yes	4.4
Concrete Containment Tendon Prestress	Yes	4.5
Containment Liner Plate, Metal Containments, and Penetrations Fatigue	Yes	4.6
Response to NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification”	Yes	4.3.1
Response to NRC Bulletin 88-08, “Thermal Stresses in Piping Connected to Reactor Cooling Systems”	Yes	4.3.1
Fatigue of Cranes (Crane Cycle Limits)	Yes	4.7.6
Fatigue of the Spent Fuel Pool Liner	No (Note 3)	N/A
Corrosion Allowance Calculations	No (Note 4)	N/A
Flaw Growth Due to Stress Corrosion Cracking	No (Note 5)	N/A
Predicted Lower Limit	Yes	4.5

Note 1: High energy line break is not a TLAA for PBN since HELB methodology does not involve time-limited assumptions defined by the current operating term.

Note 2: PBN currently has five (5) RCS component flaw evaluations identified as TLAAs in Sections 15.4-7, 15.4-8, 15.4-9, 15.4-10 and 15.4-11 of the UFSAR. Review of these five (5) flaw evaluations has determined that they do not meet Criterion 3 of 10 CFR 54.3(a) consistent with the flaw evaluation example discussed in Table 4.1-1 of NUREG-2192, because they only justify further service until a subsequent outage. However, for SLR, an additional flaw tolerance evaluation for reactor coolant loop CASS piping components meets the six TLAA criterion and is evaluated in Section 4.7.3.

Note 3: There is no fatigue analysis for the PBN spent fuel pool liner.

Note 4: No time limited metal corrosion allowance analyses were identified.

Note 5: No time limited flaw growth due to stress corrosion analyses were identified.

Table 4.1.5-2
Review of Plant-Specific TLAAs Listed in NUREG-2192, Table 4.7-1

Table 4.7-1 Examples of Potential Plant-Specific TLAA Topics	Applies to PBN	SLRA Section
PWRs		
Reactor pressure vessel underclad cracking	No (Note 1)	N/A
Leak-before-break	Yes	4.7.1 4.7.2
Reactor coolant pump flywheel fatigue crack growth	Yes	4.7.4
Response to NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification”	Yes	4.3.1
Response to NRC Bulletin 88-08, “Thermal Stresses in Piping Connected to Reactor Cooling Systems”	Yes	4.3.1
BWRs and PWRs		
Fatigue of cranes (crane cycle limits)	Yes	4.7.6
Fatigue of the spent fuel pool liner	No (Note 2)	N/A
Corrosion allowance calculations	No (Note 2)	N/A
Flaw growth due to stress corrosion cracking	No (Note 2)	N/A
Predicted lower limit	Yes	4.5

Note 1: Refer to Section 3.1.2.2.5.

Note 2: Refer to Notes 3, 4, and 5 of Table 4.1.5-1.

Table 4.1.5-3
Summary of Results —PBN TLAAs

TLAA Description	Resolution 10 CFR 54.21(c)(1) Section	Section
REACTOR VESSEL NEUTRON EMBRITTLEMENT		4.2
Neutron Fluence Projections	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.2.1
Pressurized Thermal Shock	(ii) projected to the end of the SPEO	4.2.2
Upper-Shelf Energy	(ii) projected to the end of the SPEO	4.2.3
Adjusted Reference Temperature	(ii) projected to the end of the SPEO	4.2.4
Pressure-Temperature Limits & Low Temperature Overpressure Protection (LTOP) Setpoints	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.2.5
METAL FATIGUE		4.3
Metal Fatigue of Class 1 Components	(ii) projected to the end of the SPEO (iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.3.1
ASME Code, Section III, Class I Component Fatigue Waivers	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.3.2
Metal Fatigue of Non-Class 1 Components	(i) remains valid for the SPEO	4.3.3
Environmentally-Assisted Fatigue	(ii) projected to the end of the SPEO (iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.3.4
ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRICAL EQUIPMENT	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.4
CONCRETE CONTAINMENT TENDON PRESTRESS	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.5
CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATIONS FATIGUE	(i) remains valid for the SPEO, and (iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.6

Table 4.1.5-3
Summary of Results —PBN TLAAs (Continued)

TLAA Description	Resolution 10 CFR 54.21(c)(1) Section		Section
OTHER PLANT-SPECIFIC TLAAs			
Leak-Before-Break of Reactor Coolant System Loop Piping	(ii)	projected to the end of the SPEO	4.7.1
Leak-Before-Break of Reactor Coolant System Auxiliary Piping	(i)	remains valid for the SPEO	4.7.2
Flaw Tolerance Evaluation for Reactor Coolant Loop CASS Piping Components	(ii)	projected to the end of the SPEO	4.7.3
Reactor Coolant Pump Flywheel Fatigue Crack Growth	(i)	remains valid for the SPEO	4.7.4
Reactor Coolant Pump Code Case N-481	(i)	remains valid for the SPEO	4.7.5
Crane Load Cycle Limits	(i)	remains valid for the SPEO	4.7.6

4.2. REACTOR VESSEL NEUTRON EMBRITTLEMENT

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, pressure- temperature (P-T) limits, and materials surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR Part 50, Appendices G and H. The PBN Reactor Vessel Material Surveillance AMP is described in Section B.2.3.19. The ferritic materials of the reactor vessel are subject to embrittlement due to high energy (E > 1.0 MeV) neutron exposure. Embrittlement means the material has lower toughness (i.e., will absorb less strain energy during a crack or rupture), thus allowing a crack to propagate more easily under thermal and pressure loading. Neutron embrittlement analyses are used to account for the reduction in fracture toughness associated with the cumulative neutron fluence (total number of neutrons that intersect a square centimeter of component area during the life of the plant). Since these neutron embrittlement analyses are calculated based on plant life, they are identified as TLAA. This group of TLAA concerns the effect of irradiation embrittlement on the beltline regions of the PBN Units 1 and 2 reactor vessels, and how this mechanism affects analyses that provide operating limits or address regulatory requirements.

Fracture toughness (indirectly measured in foot-pounds of absorbed energy in a Charpy impact test) is temperature dependent in ferritic materials. An initial nil-ductility reference temperature (RT_{NDT}) is associated with the transition from ductile to brittle behavior and is determined for vessel materials through a combination of Charpy and drop-weight testing. Toughness increases with temperature up to a maximum value called the “upper-shelf energy,” or USE. Neutron embrittlement results in a decrease in the USE (maximum toughness) of the reactor vessel steels.

To reduce the potential for brittle fracture during reactor vessel operation, changes in material toughness as a function of neutron radiation exposure (fluence) are accounted for through the use of operating P-T limits that are included in the PBN Technical Specifications. The P-T limits account for the decrease in material toughness of the reactor vessel beltline materials that are predicted to receive a cumulative neutron exposure of 1.0 x 10^{17} neutrons/cm^2 or more during the licensed life of the plant. Since the cumulative neutron fluence will increase during the SPEO, a review is required to determine if any additional components will exceed the cumulative neutron fluence threshold value and require evaluation for neutron embrittlement. The materials that exceed this threshold are referred to as the extended beltline materials.

Based on the projected drop in toughness for each beltline material as a result of exposure to the predicted fluence values, USE calculations are performed to determine if the components will continue to have adequate fracture toughness at the end of the license to meet the required minimums. P-T limit curves are generated to provide minimum temperature limits that must be achieved during operations prior to applications of specified reactor vessel pressures. The P-T limit curves are based upon the RT_{NDT} and ΔRT_{NDT} values computed for the licensed operating period along with appropriate margins.

The reactor vessel material ΔRT_{NDT} and USE values, calculated on the basis of neutron fluence, are part of the CLB and support safety determinations. Therefore, these calculations have been identified as TLAA. The following TLAA related to neutron embrittlement are evaluated in the SLRA sections listed below:

- Neutron Fluence Projections (4.2.1)
- Pressurized Thermal Shock (4.2.2)
- Upper-Shelf Energy (4.2.3)
- Adjusted Reference Temperature (4.2.4)
- Pressure-Temperature (P-T) Limits and Low Temperature Overpressure Protection (LTOP) Setpoints (4.2.5)

4.2.1. Neutron Fluence Projections

TLAA Description

Neutron fluence is the term used to represent the cumulative number of neutrons per square centimeter that contact the reactor pressure vessel (RPV) shell. The fluence projections that quantify the number of neutrons that contact these surfaces have been used as inputs to the neutron embrittlement analyses that evaluate the reduction of fracture toughness aging effect resulting from neutron irradiation and will be treated as a TLAA.

TLAA Evaluation

The first step in updating fluence projections for 80 years is to estimate the power history based upon actual unit operating history and a conservative capacity factor estimate for future cycles. Units 1 and 2 are currently licensed for 60 years of operation; therefore, with a 20-year license renewal, the subsequent license renewal term is 80 years.

EFPY Projections

EFPY values for Unit 1 and 2 at the end of the most recent fuel cycle (EOC) are as follows:

Unit 1: EOC38, March 2019 - 39.3 EFPY

Unit 2: EOC37, March 2020 - 39.7 EFPY

The EFPY projections through the end of the SPEO for a unit is the sum of the accumulated EFPY and the projected future EFPY. EFPY at the end of 60 years of operation was calculated to be 53 EFPY. An estimate of the EFPY at the end of 80 years of operation can be made by assuming a 95 percent capacity factor for the 20-year SPEO. Using this approach, the projected 80-year EFPY for both Units 1 and 2 is 72 EFPY.

Fluence Projections

Updated neutron fluence calculations for PBN Units 1 and 2 were performed for SLR and are documented in Tables 2.4-5 and 2.5-5 of Westinghouse WCAP-18555-NP, Revision 1, “Point Beach Units 1 and 2 Time-Limited Aging Analyses on Reactor Vessel Integrity for Subsequent License Renewal” (Reference 4.8.1). The neutron transport methodology used to generate the data followed the guidance of Regulatory Guide 1.190 and is consistent with the NRC approved methodology described in

WCAP-18124-NP-A (Reference 4.8.2). Updated neutron fluence calculations were used as an input to the RPV integrity evaluations in support of initial license renewal.

Discrete ordinates transport calculations were performed on a fuel-cycle-specific basis to determine the neutron and gamma ray environment within the PBN Unit 1 reactor geometry. This geometry is identical to Unit 2, so it is applicable to both units. The specific methods applied are consistent with those described in WCAP-18124-NP-A. All the transport calculations were carried out using the three-dimensional discrete ordinates code RAPTOR-M3G and the BUGLE-96 cross-section library. The BUGLE-96 library provides a 67-group coupled neutron-gamma ray cross-section data set produced specifically for light water reactor applications.

The RAPTOR-MG3 model extends radially from the centerline of the reactor core out to a location interior to the reactor pressure vessel (RPV) concrete shield wall and over an axial span from an elevation nine feet below the active fuel to eight feet above the active fuel. In addition to the core, reactor vessel internals, RPV, and concrete shield wall, the RAPTOR-M3G model includes explicit representations of the surveillance capsules, RPV cladding, and the insulation located external to the RPV. The RPV supports extending through the shield wall and various cut-outs in the shield wall are also included.

From a neutronic standpoint, the inclusion of the surveillance capsules and associated RPV support structure in the analytical model is significant. Since the presence of the capsules and structure has a marked impact on the magnitude of the neutron flux as well as on the relative neutron and gamma ray spectra at dosimetry locations within the capsules, a meaningful evaluation of the radiation environment internal to the capsules can be made only when these perturbation effects are properly accounted for in the analysis.

Comparisons of the measurement results from the in-vessel surveillance capsules and ex-vessel sensor set irradiations with corresponding analytical predictions were used to demonstrate compliance with the requirements of Regulatory Guide 1.190 as well as to support the uncertainty estimates associated with the calculated exposure levels. These comparisons were examined on two levels. In the first instance, calculations of individual sensor reaction rates were compared directly with the measurement data from the counting laboratory. This level of comparison was not impacted by the least squares evaluations of the sensor sets. In the second case, calculated values of neutron exposure rates in terms of fast neutron fluence rate (E > 1.0 MeV) and iron atom displacement rate were compared with the best estimate exposure rates obtained from the least-squares evaluation.

Exposure Results

Table 4.2.1-1 and Table 4.2.1-2 summarize the results of the fluence projections to 72 EFPY for Units 1 and 2 RPV materials, respectively. Table 4.2.1-1 and Table 4.2.1-2 assume a 10 percent bias on peripheral fuel assemblies for future cycles and provide the maximum projected fast neutron fluence (E > 1.0 MeV) for the various RPV materials. The neutron exposure data provided in Table 4.2.1-1 and Table 4.2.1-2 is the maximum value at either the RPV clad/base metal interface or the RPV outer surface. Note that for regions and materials above and below the core (e.g., inlet nozzle to nozzle belt forging weld and lower shell to lower head ring circumferential weld), the neutron exposure values at the RPV outer surface can be greater than those at the clad/base metal interface.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging due to fluence on the intended function will be adequately managed for the SPEO utilizing the Neutron Fluence Monitoring AMP (Section B.2.2.2) and the Reactor Vessel Material Surveillance AMP (Section B.2.3.19). Additionally, the fluence analyses have been projected to the end of the SPEO. They are to be used as inputs in the neutron embrittlement TLAA evaluations in the remainder of Section 4.2.

Table 4.2.1-1
Calculated Maximum Fast Neutron Fluence (E > 1.0 MeV) at Unit 1 RPV Welds and Shells

Projection with 10% bias on peripheral fuel assemblies	
Material	**Fluence (n/cm^2)**
	72 EFPY
Inlet nozzle to nozzle belt forging weld (lowest extent)[(1)]	6.38E+16
Nozzle belt forging (lowest extent) (122P237)	4.81E+18
Nozzle belt forging to intermediate shell circumferential weld (SA-1426)	5.54E+18
Intermediate shell longitudinal weld (SA-775/SA-812)	4.54E+19
Intermediate shell plates (A9811-1)	7.64E+19
Intermediate shell to lower shell circumferential weld (SA-1101)	7.19E+19
Lower shell longitudinal weld (SA-847)	4.48E+19
Lower shell plates (C1423-1)	7.31E+19
Lower shell to lower head ring circumferential weld	4.68E+16

Notes

1. Also applicable to outlet nozzle/nozzle belt forging weld and safety injection nozzle/nozzle belt forging weld.

Table 4.2.1-2
Calculated Maximum Fast Neutron Fluence (E > 1.0 MeV) at Unit 2 RPV Welds and Shells

Projection with 10% bias on peripheral fuel assemblies	
Material	**Fluence (n/cm2)**
	72 EFPY
Inlet nozzle to nozzle belt forging weld (lowest extent)(1)	6.61E+16
Nozzle belt forging (lowest extent) (123V352)	6.46E+18
Nozzle belt forging to intermediate shell circumferential weld (21935)	7.35E+18
Intermediate shell forging (123V500)	7.80E+19
Intermediate shell to lower shell circumferential weld (SA-1484)	7.34E+19
Lower shell forging (122W195)	7.71E+19
Lower shell to lower head ring circumferential weld	5.08E+16

Notes

1. Also applicable to outlet nozzle/nozzle belt forging weld and safety injection nozzle/nozzle belt forging weld.

4.2.2. <u>Pressurized Thermal Shock</u>

TLAA Description

A limiting condition on RV integrity known as Pressurized Thermal Shock (PTS) may occur during a severe system transient such as a small-break loss-of-coolant accident (LOCA) or steam line break. Such transients may challenge the integrity of the RV under the following conditions: severe overcooling of the inside surface of the vessel wall followed by repressurization, significant degradation of vessel material toughness caused by radiation embrittlement, and the presence of a critical-size defect anywhere within the vessel wall.

10 CFR 50.61(b)(1) provides rules for protection against PTS events for pressurized water reactors. Licensees are required to perform an updated assessment of the projected values of the PTS reference temperature (RT_{PTS}) whenever there is a significant change in projected values of RT_{PTS} or upon a request for a change in the expiration date for operation of the facility. The current analyses, evaluated for 50 EFPY fluence values predicted for 60 years of operation for Unit 1 and 50 EFPY fluence values predicted for 60 years of operation for Unit 2 (Reference ML14126A378), are TLAAs requiring evaluation for 80 years since a change in the operating license term of the facility is being requested.

TLAA Evaluation

10 CFR 50.61(c) provides two methods for determining RT_{PTS}. These methods are also described as Positions 1 and 2 in Regulatory Guide 1.99. Position 1 applies for

material without credible surveillance data available and Position 2 is used for material with two or more credible surveillance data sets available. The RT_{PTS} values are calculated for both Positions 1 and 2 by following the guidance in Regulatory Guide 1.99 (Sections 1.1 and 2.1, respectively), using the copper and nickel content of the Units 1 and 2 beltline materials, and SPEO fluence projections.

These accepted methods were used with the surface fluence values from Tables 4.2.1-1 and 4.2.1-2 to calculate the following RT_{PTS} values for the Units 1 and 2 RV materials at 72 EFPY. The SPEO RT_{PTS} calculations are summarized in Table 4.2.3-1 for both Units 1 and 2. WCAP-18555-NP, Revision 1, provides additional details for the RT_{PTS} calculations for the beltline and extended beltline materials.

10 CFR 50.61(b)(2) establishes screening criteria for RT_{PTS} as 270°F for plates, forgings, and longitudinal welds and 300°F for circumferential welds. All of the beltline materials in the Unit 1 and Unit 2 RVs are below the RT_{PTS} screening criteria values of 270°F for base metal and longitudinal welds, and 300°F for circumferentially oriented welds through the SPEO (72 EFPY).

Westinghouse WCAP-18555-NP, Revision 1, provides the details of the PTS evaluation for SLR. The limiting RTPTS value for the Unit 1 base metal or longitudinal weld at 72 EFPY is 248.9°F, which corresponds to the intermediate shell longitudinal weld. The limiting RTPTS value for the Unit 1 circumferentially oriented welds at 72 EFPY is 254.0°F, which corresponds to the intermediate to lower shell circumferential weld. The limiting RTPTS value for the Unit 2 base metal at 72 EFPY is 158.4°F, which corresponds to the intermediate shell forging utilizing credible surveillance capsule data. The limiting RTPTS value for the Unit 2 circumferentially oriented welds at 72 EFPY is 292.6°F, which corresponds to the intermediate to lower shell circumferential weld.

The Units 1 and 2 materials remain below the 10 CFR 50.61 screening criteria.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The PTS analyses have been projected to the end of the SPEO.

Table 4.2.2-1: RT_{PTS} Calculations for PBN Units 1 and 2 Reactor Vessel Beltline Materials

Material	Heat #	CF[a]	Surface Fluence[b] (x 10^{19} n/cm², E > 1.0 MeV)	Surf. FF[c]	$RT_{NDT(U)}$[d] (ºF)	Predicted ΔRT_{NDT} (ºF)	σ_u (ºF)	σ_Δ[e] (ºF)	M (ºF)	RT_{PTS} (ºF)
Unit 1										
Nozzle Belt Forging	122P237	77.0	0.481	0.796	50	61.3	0	17	34.0	145.3
Intermediate Shell Plate	A9811-1	88.0	7.64	1.477	1	129.9	26.9	17	63.6	194.6
with credible surveillance data[f]		79.9	7.64	1.477	1	118.0	26.9	8.5	56.4	175.4
Lower Shell Plate	C1423-1	55.3	7.31	1.470	1	81.3	26.9	17	63.6	145.9
with credible surveillance data[f]		36.1	7.31	1.470	1	53.1	26.9	8.5	56.4	110.5
NB to IS Circ. Weld (100%)	8T1762 (SA-1426)	167.0	0.554	0.835	-48.6	139.4	18.0	28	66.6	157.4
IS Long. Weld (ID 27%)	1P0815 (SA-812)	167.0	4.54	1.383	-48.6	231.0	18.0	28	66.6	248.9
IS Long. Weld (OD 73%)[g]	1P0661 (SA-775)	167.0	4.54	1.383	-48.6	231.0	18.0	28	66.6	248.9
IS to LS Circ. Weld (100%)	71249 (SA-1101)	167.6	7.19	1.467	-53.5	245.9	12.8	28	61.6	**254.0**
LS Long. Weld (100%)	61782 (SA-847)	167.0	4.48	1.380	-58.5	230.5	15.4	28	63.9	235.9
Unit 2										
Nozzle Belt Forging	123V352	76.0	0.646	0.878	40	66.7	0	17	34.0	140.7
Intermediate Shell Forging	123V500	58.0	7.80	1.480	40	85.8	0	17	34.0	159.8
with credible surveillance data[f]		68.5	7.80	1.480	40	101.4	0	8.5	17.0	158.4
Lower Shell Forging	122W195	31.0	7.71	1.478	40	45.8	0	17	34.0	119.8
with credible surveillance data[f]		42.9	7.71	1.478	40	63.4	0	8.5	17.0	120.4
NB to IS Circ. Weld	21935	170.5	0.735	0.914	-56	155.8	17.0	28	65.5	165.3
IS to LS Circ. Weld	72442 (SA-1484)	180.0	7.34	1.470	-33.2	264.7	12.2	28	61.1	**292.6**

Notes

(a) Chemistry factors (CF) are taken from Table 5-3 of WCAP-18555-NP, Revision 1.
(b) The 72 EFPY surface fluence values for the reactor vessel materials were taken from Tables 2.4-5 and 2.5-5 of WCAP-18555-NP, Revision 1 .
(c) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.
(d) $RT_{NDT(U)}$ values taken from Table 3-1 of WCAP-18555-NP, Revision 1.

(e) Per 10 CFR 50.61, the base metal $\sigma\Delta$ = 17°F when surveillance data is non-credible or not used to determine the CF, and the base metal $\sigma\Delta$ = 8.5°F when credible surveillance data is used to determine the CF. Also, per 10 CFR 50.61, the weld metal $\sigma\Delta$ = 28°F when surveillance data is non-credible or not used to determine the CF, and the weld metal $\sigma\Delta$ = 14°F when credible surveillance data is used to determine the CF. However, $\sigma\Delta$ need not exceed $0.5*\Delta RT_{NDT}$.

(f) The credibility evaluation for the PBN Units 1 and 2 surveillance data in Appendix A of this calculation determined that the PBN Unit 1 surveillance data for the plate materials are deemed credible. PBN Unit 2 surveillance forging data for the forging materials are deemed credible. Therefore, the Position 2.1 CF can be used with a reduced margin term in lieu of the Position 1.1 CF.

(g) This material is not present at the inner surface of the RV; however, the calculation is shown for information.

4.2.3. Upper-Shelf Energy

TLAA Description

The CLB Upper Shelf Energy (USE) calculations were prepared for PBN reactor vessel (RV) beltline materials for 53 EFPY. Since USE reduction is a function of the 53 EFPY fluence, which is associated with the 60-year licensed operating period, the USE calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 80 years.

TLAA Evaluation

Appendix G of 10 CFR Part 50, Paragraph IV.A.1.a, states that reactor vessel beltline materials must have Charpy USE of no less than 75 ft-lb initially, and must maintain Charpy USE throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

In accordance with Regulatory Guide 1.99, Revision 2 (Reference 1.6.28), the Charpy USE should be assumed to decrease as a function of fluence according to Figure 2 of the Regulatory Guide when credible surveillance data are not available (Position 1.2). If credible surveillance data are available, the decrease in USE may be obtained by plotting the reduced plant surveillance data on Figure 2 of the Regulatory Guide and fitting the data with a line drawn parallel to the existing lines as the upper bound of all of the data (Position 2.2).

The PBN Unit 1 reactor vessel was fabricated entirely by Babcock & Wilcox (B&W) and RV beltline (and extended beltline) materials for 80-years include the nozzle belt (upper shell) forging (122P237VA1), intermediate shell plate (A9811-1), lower shell plate (C1423-1), nozzle belt forging-to-intermediate shell plate circumferential weld (SA-1426), intermediate shell axial weld (SA-812/SA-775), intermediate shell-to-lower shell circumferential weld (SA-1101), and lower shell axial weld (SA-847). The Unit 1 inlet and outlet nozzles are fabricated from forged material and are connected to the nozzle belt (upper shell) forging using Linde 80 weld materials but are not considered extended beltline materials at 80-years since the projected fluence at the clad/base metal interface is less than 1.0E+17 n/cm^2. All Unit 1 beltline/extended beltline welds listed above are made from Linde 80 weld materials.

The PBN Unit 2 reactor vessel was fabricated by a combination of Babcock & Wilcox (B&W) and Combustion Engineering (CE). RV beltline/extended beltline materials for 80-years include the nozzle belt (upper shell) forging (123V352VA1), intermediate shell forging (123V500VA1), lower shell forging (122W195VA1), nozzle belt forging-to-intermediate shell forging circumferential weld (21935), and intermediate shell forging-to-lower shell forging circumferential weld (SA-1484). The Unit 2 inlet and outlet nozzles are fabricated from forged material and are connected to the nozzle belt (upper shell) forging using weld material fabricated by Combustion Engineering (CE) but are not considered extended beltline materials at 80-years since the projected fluence at the clad/base metal interface is less than 1.0E+17 n/cm^2. Only weld SA-1484 is made from Linde 80 weld material; weld 21935 is a non-Linde 80 weld fabricated by Combustion Engineering.

Compliance with 10 CFR Part 50, Appendix G requirements for PBN for 40-years is documented, in part, through PBN responses to NRC Generic Letter 92-01 (References ML20101J787 and ML20070C816). Through PBN transmittal letter Reference ML20101J787, BAW-2166 (Reference 4.8.3) was transmitted to the NRC to support PBN response to Generic Letter 92-01. PBN reactor vessel USE is addressed in BAW-2166, Section 6.0, wherein initial USE values are established only for the limiting Linde 80 welds SA-1101 for Unit 1, and SA-1484 for Unit 2. USE reduction at 40-years was predicted to fall below 50 ft-lbs for these limiting Linde 80 welds with resolution by an equivalent margins analysis (EMA) to be performed by the B&W Owners Group (B&WOG). PBN subsequently submitted Reference ML20070C816 to the NRC, which by reference to BAW-2222 (Reference 4.8.4), confirms the applicability and accuracy of information previously provided by Wisconsin Electric and the B&WOG in response to Generic Letter 92-01, Revision 1, "Reactor Vessel Structural Integrity" (Reference ML20101J787). In addition, BAW-2222, contains summary files for PBN Units 1 and 2 that reference BAW-2192PA (Reference 4.8.5) and BAW-2178PA (Reference 4.8.6) for demonstration of compliance with 10 CFR 50, Appendix G, for the following Linde 80 welds at 40-years.

- Unit 1—SA-1426, SA-1101, SA-812, and SA-847
- Unit 2—SA-1484

The current (60-year) EMA analysis of record for PBN Units 1 and 2 BAW-2467NP, Revision 1 (Reference 4.8.7) is reported in the NRC SER for the PBN EPU (Reference ML111170513), Section 2.1.2, Pressure-Temperature Limits and Upper-Shelf Energy. The NRC SER references BAW-2178PA, Revision 0, BAW-2192PA, Revision 0, and BAW-2467NP, Revision 1, Low Upper Shelf Toughness Fracture Mechanics Analysis of Reactor Vessel of PBN Units 1 and 2 for Extended Life through 53 Effective Full Power Years. In accordance with BAW-2467NP, Revision 1, limiting welds evaluated for PBN Unit 1 include traditional beltline Linde 80 welds SA-847 and SA-1101, and SA-1484 for PBN Unit 2. Prior to the EPU submittal, NextEra submitted BAW-2467NP, Revision 1, to the NRC for review and approval; the NRC SER is reported in Reference ML071300623. Review of the NRC SER of BAW-2467NP, Revision 1 (Reference ML071300623) and the EPU License Amendment Request (LAR) (Reference ML111170513) confirmed that no extended beltline weld materials were evaluated for PBN Unit 1 and Unit 2 for 60-years. In addition, USE reduction at 60-years for PBN beltline materials using Regulatory Guide 1.99, Revision 2, was not relied upon to support the 60-year license renewal application or the EPU submittal; the EMA of Linde 80 welds was determined to bound all beltline materials with regard to compliance to 10 CFR Part 50, Appendix G USE requirements for PBN Units 1 and 2.

For subsequent license renewal, the USE values for the beltline and extended beltline materials were determined using methods consistent with Regulatory Guide 1.99, Revision 2. Two methods may be used to predict the decrease in USE with irradiation, depending on the availability of credible surveillance capsule data as defined in Regulatory Guide 1.99, Revision 2. For vessel beltline materials that are not in the surveillance program or for locations with non-credible data, the Charpy USE is assumed to decrease as a function of fluence and copper content, as indicated in Regulatory Guide 1.99, Revision 2 (Position 1.2). When two or more credible surveillance data sets are available from the reactor, they may be used to determine the Charpy USE of the surveillance material. The surveillance data are then used in conjunction with the regulatory guide to predict the change in USE of the reactor vessel material due to irradiation (Position 2.2).

The 72 EFPY Regulatory Guide 1.99, Revision 2 (Position 1.2) USE values of the vessel materials can be predicted using the corresponding 1/4T fluence projection, the copper content of the materials, and Figure 2 in Regulatory Guide 1.99, Revision 2. The predicted Position 2.2 USE values are determined for the reactor vessel materials that are contained in the surveillance program by using the plant surveillance data along with the corresponding 1/4T fluence projection. The projected USE values were calculated to determine if the PBN Units 1 and 2 beltline and extended beltline materials remain above the 50 ft-lb limit at 72 EFPY. The results are summarized in Tables 4.2.3-1, 4.2.3-2, 4.2.3-3, and 4.2.3-4. (Note that the 72 EFPY fluence values used for the EMA and USE projections contain an additional margin than the values in Table 4.2.1-1 and Table 4.2.1-2, so that these projections are bounding.)

All PBN Unit 1 reactor vessel beltline and extended beltline materials maintain a USE value greater than 50 ft-lbs through 72 EFPY except for nozzle belt forging-to-intermediate shell plate circumferential weld (SA-1426), intermediate shell axial weld (SA-812/SA-775), intermediate shell-to-lower shell circumferential weld (SA-1101), lower shell axial weld (SA-847), and intermediate shell plate (A9811-1).

All PBN Unit 2 reactor vessel beltline and extended beltline materials maintain a USE value greater than 50 ft-lbs through 72 EFPY except for the intermediate shell forging-to-lower shell forging circumferential weld (SA-1484).

For the PBN Units 1 and 2 reactor vessel Linde 80 weld materials that do not maintain a USE value above 50 ft-lbs through 72 EFPY, an EMA was performed to demonstrate that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code. The 72 EFPY PBN EMA analyses for Linde 80 welds are reported in Framatome topical report supplement 3P/NP to BAW-2192 and supplement 2P/NP to BAW-2178, respectively (References 4.8.8 and 4.8.9).

Equivalent Margins Analysis (EMA)-Linde 80 Welds

The analytical procedure used for the 72 EFPY equivalent margins analyses (References 4.8.8 and 4.8.9) of Linde 80 welds for PBN Units 1 and 2 is in accordance with ASME Section XI, Appendix K, 2017 Edition, with selection of design transients based on the guidance in Regulatory Guide 1.161 (Reference 4.8.10). Results of the EMA are summarized below.

Levels A & B Service Loads

Reactor Vessel Shell Welds

- The limiting RV Linde 80 weld is PBN Unit 1 axial weld (SA-812), which bounds all Unit 1 and Unit 2 Linde 80 welds. With factors of safety of 1.15 on pressure and 1.0 on thermal and mechanical loading on axial weld (SA-812), the applied J-integral (J_1) is less than the J-integral of the material at a ductile flaw extension of 0.10 in. ($J_{0.1}$). The ratio $J_{0.1}/J_1$ is greater than the required value of 1.0.

- With a factor of safety of 1.25 on pressure and 1.0 on thermal and mechanical loading on axial weld (SA-812), flaw extensions are ductile and stable since the slope of the applied J-integral curve is less than the slope of the lower bound J-R curve at the point where the two curves intersect.

Levels C & D Service Loads

Reactor Vessel Shell Welds

- With a factor of safety of 1.0 on loading, the applied J-integral (J_1) for the limiting reactor vessel weld (SA-812) is less than the lower bound J-integral of the material at a ductile flaw extension of 0.10 inch ($J_{0.1}$) with a ratio $J_{0.1}/J_1$ is greater than the required value of 1.0.

- With a factor of safety of 1.0 on loading, flaw extensions are ductile and stable for the limiting reactor vessel weld (SA-812) since the slope of the applied J-integral curve is less than the slopes of both the lower bound and mean J-R curves at the points of intersection.

- For reactor vessel weld (SA-812) flaw growth is stable at much less than 75% of the vessel wall thickness. Also, the remaining ligament is sufficient to preclude tensile instability by a large margin.

B&WOG J-R Model 6B

B&WOG J-R Model 6B is shown to be applicable to PBN Units 1 and 2, as reported in Reference 4.8.8, Appendix A. Specifically, the PBN Linde 80 material properties (i.e., copper content) and 80-year projected fluence at the 1/4T location are within the range of explanatory variables used to develop B&WOG Model 6B, which is qualified for subsequent license renewal. Therefore, use of B&WOG Model 6B mean and lower bound J-integral resistance values at crack extensions of 0.1 inches are appropriate for the Linde 80 weld EMA's for PBN Units 1 and 2.

Equivalent Margins Analysis (EMA)-Unit 1 Intermediate Shell Plate A9811-1

As reported in Table 4.2.3-3, PBN Unit 1 intermediate shell plate (heat A9811-1) has a predicted 72 EFPY USE value that is just below 50 ft-lbs at 80-years; all remaining beltline and extended beltline plate and forging materials for Units 1 and 2 are above 50 ft-lbs at 72 EFPY. IS plate A9811-1 is made from ASTM A302B plate material with sulfur content of 0.02% and nickel content of 0.056%. In addition, it was confirmed that intermediate shell (IS) plate A9811-1 has a predicted USE greater than 50 ft-lbs at 53 EFPY (60-years) using Regulatory Guide 1.99 Revision 2, Position 2.2. Therefore, a 72 EFPY EMA is required for IS plate A9811-1 to demonstrate compliance with 10 CFR 50, Appendix G, for subsequent license renewal.

The analytical procedure used for the 72 EFPY equivalent margins analysis of IS plate A9811-1 reported in ANP-3886P/NP, Revision 0, PWROG-20043-P/NP "PBN Unit 1 IS Plate A9811-1 Equivalent Margins Analysis for SLR" (Reference 4.8.11) is in accordance with ASME Section XI, Appendix K, 2017 Edition, with selection of design transients based on the guidance in Regulatory Guide 1.161. The methodology for calculation of Japplied for IS plate A9811-1 is consistent with the methodology used to calculate Japplied for Linde 80 welds (References 4.8.8 and 4.8.9); both axial and circumferential flaws are postulated in intermediate shell plate A9811-1. The J-integral resistance model used for IS plate A9811-11 is from NUREG/CR-5265, Specimen V-50-101, 6T, adjusted for temperature and use of the CVN model in accordance with Reference ML17059A282. Regulatory Guide 1.161, Equations (26)-(29), are used to develop the temperature and crack extension indexing reported in Reference ML17059A282.

Temperatures used to adjust NUREG/CR-5265 J-R Specimen V-50-101 data are consistent with the temperatures reported in BAW-2192, Supplement 3, for Levels A and B Service Loads, and in BAW-2178, Supplement 2, for Levels C and D Service Loads. CVN values used to adjust Specimen V-50-101, 6T, are 49 ft-lbs in the weak direction (for circumferential flaws) at the bottom and the top of the plate, and 75.35 ft-lbs and 90.23 ft-lbs in the strong direction (for axial flaws) at the bottom and top of the plate, respectively. A statistical factor applied to the temperature/CVN indexing of J-R specimen V50-101 of approximately 1.0 was selected based on comparison of recent ASTM A302B plate J-R test data for a San Onofre high sulfur ASTM A302B plate, heat A0399 (Reference 4.8.12) with sulfur content of 0.0195%, irradiated to a fluence of 3.85E+19 n/cm^2, to CVN values obtained using Regulatory Guide 1.161, Equations (26)-(29). In addition, RVID2 data was reviewed relative to measured (direct method) unirradiated data. The calculated mean – 2Sσ value of the initial CvUSE is equal to 70.2 ft-lbs, which is greater than 69.9 ft-lbs. Therefore, the CVN value of 49 ft-lbs in the weak direction (circumferential flaws), is considered appropriate based on a review of industry data. Results of the EMA for PBN Unit 1 IS plate A9811-1 are summarized below (Reference 4.8.11).

Levels A & B Service Loads

- The applied J-integral values for the assumed 1/4-thickness inside-surface circumferential and axial flaws in the IS plate (A9811-1) with a structural factor of 1.15 on pressure loading is within the material fracture toughness J-resistance at 0.1-inch crack extension. The ratio $J_{0.1}/J_1$ is greater than the required value of 1.0 for both the axial and circumferential postulated flaws. The limiting flaw is an axial flaw at the top of IS plate A9811-1.

- With a structural factor of 1.25 on pressure and 1.0 on thermal loading, flaw extensions are ductile and stable since the slope of the applied J-integral curve is less than the slope of the lower bound J-R curve for crack extensions less than or equal to 0.10-inches.

Levels C & D Service Loads

- With a structural factor of 1.0 on loading, the applied J-integral (J_1) for the IS plate (A9811-1) postulated axial and circumferential and flaws are less than the lower bound J-integral of the material at a ductile flaw extension of 0.10 inch ($J_{0.1}$) with a ratio $J_{0.1}/J_1$ is greater than the required value of 1.0.

- With a structural factor of 1.0 on loading, flaw extensions are ductile and stable for the IS plate (A9811-1) postulated circumferential and axial flaws since the slopes of the applied J-integral curves are less than the slopes of the lower bound J-R curves for crack extensions less than or equal to 0.10-inches.

- For the postulated circumferential and axial flaws in IS plate (A9811-1), the flaw growth is stable at much less than 75% of the vessel wall thickness. Also, the remaining ligament is sufficient to preclude tensile instability by a large margin.

The margins ($J_{0.1}/J_1$) at 72 EFPY for PBN Unit 1 IS plate A9811-1 for service loads A-D are approximately similar to that of PBN Unit 1 Linde 80 Weld SA-812.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The USE analyses have been projected to the end of the SPEO. They may be used as inputs to 72 EFPY P-T limits for the SPEO.

Table 4.2.3-1
PBN Unit 1 Predicted Regulatory Guide 1.99, Rev. 2 Position 1.2 USE Values at 72 EFPY

Reactor Vessel Material	Cu (Wt.%)	1/4T EOL Fluence, n/cm2 (E>1.0 MeV)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)	Projected EOL USE (ft-lb)
Nozzle Belt (Upper Shell) Forging (NBF)	0.11	3.32E+18	76.1	15.4	64.4
Intermediate Shell (IS) Plate	0.20	5.29E+19	69.9 **EMA**[B]	43.0	39.8 **EMA**[B]
Lower Shell (LS) Plate	0.12	5.06E+19	77.9	30.8	53.9
NBF to IS Circ. Weld (100%)	0.19	3.83E+18	**EMA**[B]	26.3	**<50 ft-lbs**
IS Axial Weld (ID 27%)	0.17	3.14E+19	**EMA**[B]	40.7	**<50 ft-lbs**
IS Axial Weld (OD 73%)[A]	0.17	N/A	**EMA**[C]	N/A	**EMA**[C]
IS to LS Circ. Weld (100%)	0.23	4.98E+19	**EMA**[B]	54.1	**<50 ft-lbs**
LS Axial Weld (100%)	0.23	3.10E+19	**EMA**[B]	48.4	**<50 ft-lbs**

Notes

A. 1/4T is not applicable to this location, location is beyond 1/4T from base metal-clad interface
B. Equivalent Margins Analysis (EMA) required since USE < 50 ft-lbs
C. Bounded by EMA for IS axial weld (ID 27%); copper contents of both welds are identical and with use of a copper fluence J-R model, evaluation of IS weld (ID 27%) is bounding

Table 4.2.3-2
PBN Unit 2 Predicted Regulatory Guide 1.99, Rev. 2 Position 1.2 USE Values at 72 EFPY

Reactor Vessel Material	Cu (Wt.%)	1/4T EOL Fluence, n/cm^2 (E>1.0 MeV)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)	Projected EOL USE (ft-lb)
Nozzle Belt (Upper Shell) Forging (NBF)	0.11	4.52E+18	89.3	16.6	74.5
Intermediate Shell (IS) Forging	0.09[A]	5.50E+19	111.2	28.4	79.6
Lower Shell (LS) Forging	0.05[A]	5.42E+19	95.7	28.3	68.6
NBF to IS Circ. Weld (100%)	0.18	5.82E+18	109	28.2	78.3
IS to LS Circ. Weld (100%)	0.26	5.18E+19	**EMA[C]**	54.3[B]	**<50 ft-lbs**

Notes

A. Copper content of 0.10 wt% used.
B. Projected values exceed the bound of Figure 2 Upper Limit curve from Regulatory Guide 1.99, Revision 2; therefore, reported values are calculated using upper limit curve.
C. Equivalent Margins Analysis required since USE < 50 ft-lbs.

Table 4.2.3-3
PBN Unit 1 Predicted Regulatory Guide 1.99, Rev. 2 Position 2.2 USE Values at 72 EFPY

Reactor Vessel Material	Cu (Wt.%)	1/4T EOL Fluence, n/cm^2 (E>1.0 MeV)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)	Projected EOL USE (ft-lb)
Intermediate Shell (IS) Plate	0.20	5.29E+19	69.9 **EMA[B]**	30	49.0 **EMA[B]**
Lower Shell (LS) Plate	0.12	5.06E+19	77.9	Note A	Note A
IS to LS Circ. Weld (100%)	0.23	4.98E+19	**EMA[B]**	50.4	**<50 ft-lb**
LS Axial Weld (100%)	0.23	3.10E+19	**EMA[B]**	47.3	**<50 ft-lb**

Notes

A. CvUSE increases for surveillance specimens as fluence increases; therefore, predicted model per Position 2.2 of Regulatory Guide 1.99, Revision 2, is not calculated.
B. Equivalent Margins Analysis required since USE < 50 ft-lbs.

Table 4.2.3-4
PBN Unit 2 Predicted Regulatory Guide 1.99, Rev. 2 Position 2.2 USE Values at 72 EFPY

Reactor Vessel Material	Cu (Wt.%)	1/4T EOL Fluence, n/cm^2 (E>1.0 MeV)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)	Projected EOL USE (ft-lb)
Intermediate Shell (IS) Forging	0.09	5.50E+19	111.2	28.4[A]	79.6[A]
Lower Shell (LS) Forging	0.05	5.42E+19	95.7	28.3[A]	68.6[A]
NBF to IS Circ. Weld (100%)	0.18	5.82E+18	109	34.9	71.0
IS to LS Circ. Weld (100%)	0.26	5.18E+19	**EMA[B]**	46.3	**<50 ft-lbs**

Notes

A. Value predicts Surveillance Upper Bound at Cu wt% < 0.10. Surveillance Upper Bound is conservatively modeled at Cu wt% = 0.10.
B. Equivalent Margins Analysis required since USE < 50 ft-lbs

4.2.4. Adjusted Reference Temperature

TLAA Description

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the beltline P-T limit curves to account for irradiation effects. Regulatory Guide 1.99, Revision 2, provides the methodology for determining the ART of the limiting material. The initial nil ductility reference temperature, RT_{NDT}, is the temperature at which a non-irradiated metal (ferritic steel) changes in fracture characteristics from ductile to brittle behavior. RT_{NDT} is evaluated according to the procedures in the ASME Boiler and Pressure Vessel Code, Section III, Paragraph NB-2331. Neutron embrittlement increases the RT_{NDT} beyond its initial value.

10 CFR Part 50, Appendix G, defines the fracture toughness requirements for the life of the vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lb index temperatures from the average Charpy curves measured before and after irradiation. This increase (ΔRT_{NDT}) means that higher temperatures are required for the material to continue to act in a ductile manner. The ART is defined as: Initial RT_{NDT} + (ΔRT_{NDT}) + Margin. Since the ΔRT_{NDT} value is a function of 50 EFPY fluence, these ART calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 80 years.

TLAA Evaluation

Table 4.2.4-1 provides the surface, 1/4T, and 3/4T fluence and fluence factor (FF) values for PBN Units 1 and 2 at 72 EFPY, which are needed to calculate ART values. The ART calculations for both PBN Units 1 and 2 at 72 EFPY are summarized in Table 4.2.4-2 for 1/4T and Table 4.2.4-3 for 3/4T. WCAP-18555-NP, Revision 1, provides additional details for the ART calculations for the beltline and extended beltline materials.

The ART values of the limiting beltline materials at 72 EFPY for each unit are listed below:

- The limiting 72 EFPY ART values for PBN Unit 1 correspond to the intermediate longitudinal weld (Heat # 1P0815 (SA-812)).
- The limiting 72 EFPY ART values for PBN Unit 2 correspond to the intermediate to lower shell circumferential weld (Heat # 72442 (SA-1484)).

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The ART analyses have been projected to the end of the SPEO. They may be used as inputs to 72 EFPY P-T limits for the SPEO.

Table 4.2.4-1
PBN Units 1 and 2 Fluence and Fluence Factor Values for the Surface, 1/4T, and 3/4T Locations at 72 EFPY

Material	Surface Fluence(a) (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T Fluence(b) (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T FF(c)	3/4T Fluence(b) (x 10^{19} n/cm^2, E > 1.0 MeV)	3/4T FF(c)
Unit 1					
Nozzle Belt Forging	0.481	0.326	0.692	0.149	0.502
Intermediate Shell Plate	7.64	5.17	1.409	2.37	1.233
Lower Shell Plate	7.31	4.95	1.400	2.27	1.222
NB to IS Circ. Weld	0.554	0.375	0.729	0.172	0.534
IS Long. Weld	4.54	3.07	1.296	1.41	1.095
IS to LS Circ. Weld	7.19	4.87	1.397	2.23	1.217
LS Long. Weld	4.48	3.03	1.293	1.39	1.092
Unit 2					
Nozzle Belt Forging	0.646	0.437	0.770	0.200	0.570
Intermediate Shell Forging	7.80	5.28	1.413	2.42	1.238
Lower Shell Forging	7.71	5.22	1.411	2.39	1.235
NB to IS Circ. Weld	0.735	0.498	0.805	0.228	0.601
IS to LS Circ. Weld	7.34	4.97	1.401	2.28	1.223

Notes

(a) The 72 EFPY surface fluence values for the reactor vessel materials were taken from Tables 2.4-5 and 2.5-5 of WCAP-18555-NP, Revision 1.

(b) 1/4T and 3/4T fluence values were calculated from the surface fluence, the reactor vessel beltline thickness (6.5 inches) and equation $f = f_{surf} * e^{-0.24 (x)}$ from Regulatory Guide 1.99, Revision 2, where x = the depth into the vessel wall (inches)

(c) FF = fluence factor = $f^{(0.28 - 0.10*\log (f))}$

Table 4.2.4-2: Calculation of the PBN Units 1 and 2 ART Values at the 1/4T Location for the Reactor Vessel Beltline Materials at 72 EFPY

Material	Heat #	R.G. 1.99, Rev. 2 Position	CF[(a)]	1/4T Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T FF[(b)]	$RT_{NDT(U)}$[(c)] (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ[(d)] (°F)	M (°F)	ART (°F)
Unit 1											
Nozzle Belt Forging	122P237	1.1	77.0	0.326	0.692	50	53.3	0	17	34.0	137.3
Intermediate Shell Plate	A9811-1	1.1	88.0	5.17	1.409	1	124.0	26.9	17	63.6	188.6
with credible surveillance data[(e)]		2.1	79.9	5.17	1.409	1	112.6	26.9	8.5	56.4	170.0
Lower Shell Plate	C1423-1	1.1	55.3	4.95	1.400	1	77.4	26.9	17	63.6	142.1
with credible surveillance data[(e)]		2.1	36.1	4.95	1.400	1	50.6	26.9	8.5	56.4	108.0
NB to IS Circ. Weld (100%)	8T1762 (SA-1426)	1.1	167.0	0.375	0.729	-48.6	121.7	18.0	28	66.6	139.7
IS Long. Weld (ID 27%)	1P0815 (SA-812)	1.1	167.0	3.07	1.296	-48.6	216.5	18.0	28	66.6	**234.5**
IS Long. Weld (OD 73%)	1P0661 (SA-775)	1.1	167.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
IS to LS Circ. Weld (100%)	71249 (SA-1101)	1.1	167.6	4.87	1.397	-53.5	234.1	12.8	28	61.6	242.2
LS Long. Weld (100%)	61782 (SA-847)	1.1	167.0	3.03	1.293	-58.5	216.0	15.4	28	63.9	221.4
Unit 2											
Nozzle Belt Forging	123V352	1.1	76.0	0.437	0.770	40	58.5	0	17	34.0	132.5
Intermediate Shell Forging	123V500	1.1	58.0	5.28	1.413	40	82.0	0	17	34.0	156.0
with credible surveillance data[(e)]		2.1	68.5	5.28	1.413	40	96.8	0	8.5	17.0	153.8
Lower Shell Forging	122W195	1.1	31.0	5.22	1.411	40	43.7	0	17	34.0	117.7
with credible surveillance data[(e)]		2.1	42.9	5.22	1.411	40	60.5	0	8.5	17.0	117.5
NB to IS Circ. Weld	21935	1.1	170.5	0.498	0.805	-56	137.3	17.0	28	65.5	146.8
IS to LS Circ. Weld	72442 (SA-1484)	1.1	180.0	4.97	1.401	-33.2	252.2	12.2	28	61.1	**280.1**

Notes

(a) Chemistry factors (CF) are taken from Table 5-3 of WCAP-18555-NP, Revision 1.
(b) Fluence and Fluence Factors taken from Table 7-2 of WCAP-18555-NP, Revision 1.
(c) $RT_{NDT(U)}$ values taken from Table 3-1 of WCAP-18555-NP, Revision 1.
(d) Per the guidance of Regulatory Guide 1.99, Revision 2, the base metal $\sigma\Delta$ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal $\sigma\Delta$ = 8.5°F for Position 2.1 with credible surveillance data. Also, per Regulatory Guide 1.99, Revision 2, the weld metal $\sigma\Delta$ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal $\sigma\Delta$ = 14°F for Position 2.1 with credible surveillance data. However, $\sigma\Delta$ need not exceed $0.5*\Delta RT_{NDT}$ for either base metals or welds, with or without surveillance data.
(e) Credibility evaluation for the PBN Units 1 and 2 surveillance data in Appendix A of WCAP-18555-NP, Revision 1, determined that the PBN Unit 1 surveillance data for the plate materials are deemed credible. PBN Unit 2 surveillance forging data for the forging materials are deemed credible. Therefore, the Position 2.1 CF can be used with a reduced margin term in lieu of the Position 1.1 CF.

Table 4.2.4-3: Calculation of the PBN Units 1 and 2 ART Values at the 3/4T Location for the Reactor Vessel Beltline Materials at 72 EFPY

Material	Heat #	R.G. 1.99, Rev. 2 Position	CF[(a)]	3/4T Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	3/4T FF[(b)]	$RT_{NDT(U)}$[(c)] (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ[(d)] (°F)	M (°F)	ART (°F)
Unit 1											
Nozzle Belt Forging	122P237	1.1	77.0	0.149	0.502	50	38.6	0	17	34.0	122.6
Intermediate Shell Plate	A9811-1	1.1	88.0	2.37	1.233	1	108.5	26.9	17	63.6	173.1
with credible surveillance data[(e)]		2.1	79.9	2.37	1.233	1	98.5	26.9	8.5	56.4	155.9
Lower Shell Plate	C1423-1	1.1	55.3	2.27	1.222	1	67.6	26.9	17	63.6	132.2
with credible surveillance data[(e)]		2.1	36.1	2.27	1.222	1	44.1	26.9	8.5	56.4	101.5
NB to IS Circ. Weld (100%)	8T1762 (SA-1426)	1.1	167.0	0.172	0.534	-48.6	89.2	18.0	28	66.6	107.1
IS Long. Weld (ID 27%)	1P0815 (SA-812)	1.1	167.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
IS Long. Weld (OD 73%)	1P0661 (SA-775)	1.1	167.0	1.41	1.095	-48.6	182.9	18.0	28	66.6	**200.9**
IS to LS Circ. Weld (100%)	71249 (SA-1101)	1.1	167.6	2.23	1.217	-53.5	204.0	12.8	28	61.6	212.1
LS Long. Weld (100%)	61782 (SA-847)	1.1	167.0	1.39	1.092	-58.5	182.3	15.4	28	63.9	187.7
Unit 2											
Nozzle Belt Forging	123V352	1.1	76.0	0.200	0.570	40	43.3	0	17	34.0	117.3
Intermediate Shell Forging	123V500	1.1	58.0	2.42	1.238	40	71.8	0	17	34.0	145.8
with credible surveillance data[(e)]		2.1	68.5	2.42	1.238	40	84.8	0	8.5	17.0	141.8
Lower Shell Forging	122W195	1.1	31.0	2.39	1.235	40	38.3	0	17	34.0	112.3
with credible surveillance data[(e)]		2.1	42.9	2.39	1.235	40	53.0	0	8.5	17.0	110.0
NB to IS Circ. Weld	21935	1.1	170.5	0.228	0.601	-56	102.5	17	28	65.5	112.0
IS to LS Circ. Weld	72442 (SA-1484)	1.1	180.0	2.28	1.223	-33.2	220.1	12.2	28	61.1	**248.0**

Notes

(a) Chemistry factors (CF) are taken from Table 5-3 of WCAP-18555-NP, Revision 1 .
(b) Fluence and Fluence Factors taken from Table 7-2 of WCAP-18555-NP, Revision 1.
(c) $RT_{NDT(U)}$ values taken from Table 3-1 of WCAP-18555-NP, Revision 1.
(d) Per the guidance of Regulatory Guide 1.99, Revision 2, the base metal $\sigma\Delta$ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal $\sigma\Delta$ = 8.5°F for Position 2.1 with credible surveillance data. Also, per Regulatory Guide 1.99, Revision 2, the weld metal $\sigma\Delta$ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal $\sigma\Delta$ = 14°F for Position 2.1 with credible surveillance data. However, $\sigma\Delta$ need not exceed 0.5 * ΔRT_{NDT} for either base metals or welds, with or without surveillance data.
(e) The credibility evaluation for the PBN Units 1 and 2 surveillance data in Appendix A of this calculation determined that the PBN Unit 1 surveillance data for the plate materials are deemed credible. PBN Unit 2 surveillance forging data for the forging materials are deemed credible. Therefore, the Position 2.1 CF can be used with a reduced margin term in lieu of the Position 1.1 CF.

4.2.5. Pressure-Temperature Limits and Low Temperature Overpressure Protection (LTOP) Setpoints

TLAA Description

10 CFR Part 50 Appendix G requires that the RPV be maintained within established pressure-temperature (P-T) limits, including heatup and cooldown operations. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the RPV is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated RPV fluence effect on fracture toughness.

The current P-T limits are based upon fluence projections that were considered to represent plant operating conditions through 50 EFPY. Since the P-T limits are currently based upon a defined operating period, they satisfy the criteria of 10 CFR 54.3(a) and have been identified as TLAAs.

TLAA Evaluation

In accordance with NUREG-2192, Section 4.2.2.1.4, the P-T limits for the SPEO need not be submitted as part of the SLRA since the P-T limits are required to be updated through the 10 CFR 50.90 licensing process when necessary for P-T limits that are located in the Technical Specifications. The 10 CFR 50.90 process will ensure that the P-T limits for the SPEO will be updated prior to expiration of the P-T limits for the current period of operation.

The current PBN Units 1 and 2 heatup and cooldown curves were calculated using the most limiting value of RT_{NDT} corresponding to the limiting material in the beltline region of the reactor vessel for 50 EFPY based on EPU fluences. PBN Technical Specification 3.4.3 states that the RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the Pressure Temperature Limits Report (PTLR). Prior to exceeding 50 EFPY (approximately the end of year 2029), new P-T limit curves will be generated to cover plant operation beyond 50 EFPY. The P-T limit curves will be developed using NRC-approved analytical methods. The analysis of the P-T curves will consider locations outside of the beltline such as nozzles, penetrations and other discontinuities to determine if more restrictive P-T limits are required than would be determined by considering only the reactor vessel beltline materials.

Additionally, PBN Technical Specification 3.4.12 also refers to the PTLR for the power operated relief valve (PORV) lift settings to mitigate the consequences of LTOP events. Each time the P-T limit curves are revised, the LTOP PORV setpoints must be reevaluated. Therefore, LTOP protection limits are considered part of the calculation of P-T curves.

The P-T limit curves and LTOP PORV setpoints will be updated (if required) and a Technical Specification change request will be submitted for approval prior to exceeding the current 50 EFPY limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging on the intended function(s) of the reactor vessels will be adequately managed for the SPEO. The Reactor Vessel Material Surveillance AMP (Section B.2.3.19) will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval prior to exceeding the current terms of applicability in the Technical Specifications for PBN Units 1 and 2.

4.3. METAL FATIGUE

Fatigue analyses are required for components designed to ASME Code, Section III, Class 1. Also, certain other codes such as ASME Code, Section III, Class 2 and 3, USAS (ANSI) B31.1, “Power Piping”, and ASME Section VIII, “Rules for Construction of Pressure Vessels”, Division 2, may require a fatigue analysis or assume a stated number of full-range thermal and displacement transient cycles. NUREG-2192 also provides examples of components likely to have fatigue TLAAs within the CLB that would require evaluation for the SPEO. Searches were performed to identify these and any other potential fatigue TLAAs within the current licensing bases for Units 1 and 2. Each of the potential TLAAs were evaluated against the six elements of the TLAA definition specified in 10 CFR 54.3. Those that were identified as fatigue TLAAs are described and evaluated in the following subsections:

- Metal Fatigue of Class 1 Component (4.3.1)
- ASME Code, Section III, Class I Component Fatigue Waivers (4.3.2)
- Metal Fatigue of Non-Class 1 Components (4.3.3)
- Environmentally-Assisted Fatigue (4.3.4)

4.3.1. Metal Fatigue of Class 1 Components

TLAA Description

The PBN reactor vessels, reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and pressurizer surge lines have been designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Class 1. The ASME Boiler and Pressure Vessel Code, Section III, Class 1 requires a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded. Note that metal fatigue of piping associated with the non-Class 1 reactor coolant, engineered safety feature, auxiliary, and main steam and power conversion systems in the scope of SLR is addressed in Section 4.3.3.

Fatigue analyses were prepared for the components of the PBN reactor vessels, reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and pressurizer surge lines to determine the effects of cyclic loadings resulting from changes in system temperature and pressure. These ASME Section III, Class 1 fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients described in the design specifications. The fatigue analyses were required to demonstrate that the cumulative usage factors (CUFs) will not exceed the design allowable limit of 1.0 when the components are exposed to all of the postulated transients.

Considering the calculation of fatigue usage factors is part of the CLB and is used to support safety determinations, and the number of occurrences of each transient type was based upon 60-year assumptions, these Class 1 fatigue analyses have been identified as TLAAs requiring evaluation for the SPEO.

TLAA Evaluation

Fatigue analyses are based upon numbers and amplitudes of thermal and pressure transients. UFSAR Table 4.1-8 lists each of the transient conditions and associated design cycles for PBN. The intent of the design basis transient conditions is to bound a wide range of possible events with varying ranges of severity in temperature and pressure. Current licensing basis fatigue analyses are based upon the original number of 40-year design cycles and are postulated to bound the current 60-year period of extended operation. Since the component fatigue analyses are based upon a number of cycles postulated to bound 60 years of service, these fatigue analyses are considered TLAAs and require disposition for the 80-year SPEO.

Industry operating experience has shown that actual plant operation is conservatively represented by these transient conditions and design cycles. The use of actual operating history data allows the quantification of these conservatisms in the existing component fatigue analyses. To demonstrate that the Class 1 component fatigue analyses remain valid for the SPEO, the design cycles applicable to the Class 1 components from the UFSAR were reviewed.

The PBN Fatigue Monitoring AMP confirms that the metal fatigue aging effect for components that have a fatigue or cyclic loading design basis is adequately managed. The AMP currently utilizes the software to monitor transient cycles. The software is a computerized system that identifies and counts pre-defined plant events and computes fatigue usage at pre-defined component locations. Plant transients were selected for inclusion in the FatiguePro transient monitoring software at PBN through a review of PBN cycle counting procedures, Technical Specifications and UFSAR Table 4.1-8. To support the current 60-year period of extended operation, PBN expanded the AMP to monitor additional plant cycles and additional component locations. Experience has shown this approach is conservative, because it assumes each actual transient has a severity equal to that assumed in the design basis.

For SLR, the PBN transient monitoring software was run to identify and count plant transient cycles for the components being monitored by the software. Cycle projections to 80 years of operation were computed for the counted transients, using the projection methods provided in the software. For SLR, current transient cycle counts as of December 31, 2019 were projected to the 80-year SPEO. Additional details of the evaluation of projected cycles for PBN Units 1 and 2 for 80 years are documented in Structural Integrity Associates, Inc. (SIA) Report No. 2000088.401 (Reference 4.8.13) and supporting SI calculations.

Table 4.3.1-1 provides the results of the 80-year transient cycle projections for PBN Units 1 and 2. Most nuclear power plants, including PBN, have experienced a significant declining trend in accumulation of transients over time. As shown in Table 4.3.1-1, the projected cycles for the 80-year SPEO are less than the original 40-year design cycles (CLB cycles). For SLR, the Fatigue Monitoring AMP will utilize the 80-year allowable cycle values in Table 4.3.1-1 for the cycle limits which provides margin to account for a potential increased transient rate later in the SPEO.

The severity of the Class 1 design transients was recently evaluated in Section 2.2.6 of the PBN Extended Power Uprate (EPU) license amendment request

(Reference ML110750120). That evaluation compared the EPU design parameters to the design parameters used in the pre-EPU design transients. All design transients, with the exception of steady-state fluctuations and boron concentration equilibrium were analyzed using the Westinghouse LOFTRAN computer code (Reference 4.8.14). The steady-state fluctuations and the boron concentration equilibrium transients were evaluated and revised to reflect the EPU conditions. The revised EPU design transients were determined to be conservative representations of actual plant transients and provided confidence that the component fatigue analyses are acceptable for the current plant operating life of 60 years. Since the current plant operating conditions are consistent with those evaluated for EPU, the EPU design transient severity remains conservative and valid for the proposed 80-year SPEO.

Class 1 Component Fatigue Analysis

Fatigue analyses were performed per ASME Code, Section III. Each analysis must demonstrate that the cumulative usage factor (CUF) for the component will not exceed the Code design limit of 1.0 when the component is exposed to all postulated transients. The following report sections provide a summary of the PBN Class 1 component fatigue analyses acceptability for the proposed 80-year SPEO.

Reactor Vessels

The PBN reactor vessels were designed and fabricated in accordance with Westinghouse specifications and applicable requirements of the 1965 Edition of Section III of the ASME Boiler and Pressure Vessel (B&PV) Code for the Unit 1 reactor vessel and the 1968 Edition of the ASME Code with addenda through Winter 1968 for the Unit 2 reactor vessel. Replacement reactor vessel closure heads (RVCHs), with replacement control rod drive mechanisms (CRDMs), instrument port head adaptors (IPHAs), core exit thermocouple nozzle assemblies (CETNAs) and associated components were installed at PBN during the Unit 1 and Unit 2 2005 refueling outages. The replacement RVCHs, replacement IPHAs, CETNAs and associated components were designed, fabricated, inspected and tested in accordance with the requirements of the applicable Westinghouse Design Specifications and the ASME B&PV Code for Class 1 Vessels, 1998 Edition through 2000 Addenda.

The replacement CRDMs are mounted onto the RVCHs by means of head adaptors welded to RVCH penetrations. The CRDMs consists of the internal latch assembly, the pressure vessel housing, the operating coil stack, the drive shaft assembly, and the position indicator coil stack. The CRDM pressure vessel housings are designed in accordance with the requirements of the ASME Code, Section III, Class 1, 1998 Edition through 2000 Addenda.

Table 2.2.2.3-3 of the PBN EPU license amendment request provides a summary of the CUFs for the reactor vessel components. All CUFs are below the acceptance criteria of 1.0. As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUFs for the reactor vessel components remain valid for the SPEO.

Control Rod Drive Mechanisms

The replacement CRDMs are mounted onto the RVCHs by means of head adaptors welded to RVCH penetrations. The CRDMs consists of the internal latch assembly, the pressure vessel housing, the operating coil stack, the drive shaft assembly, and the position indicator coil stack. The CRDM pressure vessel housings are designed in accordance with the requirements of the ASME Code, Section III, Class 1, 1998 Edition through 2000 Addenda.

Tables 2.2.2.4-1 and 2.2.2.4-2 of the PBN EPU license amendment request provide a summary of the CUFs for the CRDMs. All CUFs are below the acceptance criteria of 1.0. As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUFs for the CRDMs remain valid for the SPEO.

Steam Generators

PBN Units 1 and 2 began commercial operation with Westinghouse Model 44 steam generators. In 1983, PBN Unit 1 replaced the lower assembly of the Model 44 steam generators with Westinghouse Model 44F steam generators. In 1996, PBN Unit 2 installed the Westinghouse Model Δ47 steam generators in Unit 2.

All of the new lower assembly components of the Unit 1 steam generators were fabricated in accordance with the 1977 ASME Boiler and Pressure Vessel Code, Section III, through Winter 1978 Addenda. The upper shells and the original components that remained in the units were designed to the 1965 ASME Code through Summer 1966 Addenda. The upper and lower assemblies for the Unit 2 replacement steam generators were designed and manufactured in accordance with the 1986 ASME Code, Section III, NB requirements.

Tables 2.2.2.5-1 and 2.2.2.5-2 of the PBN EPU license amendment request provide a summary of the CUFs for the Unit 1 and Unit 2 steam generators, respectively. All CUFs are below the acceptance criteria of 1.0. As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUFs for the steam generators remain valid for the SPEO.

Reactor Coolant Pumps

The reactor coolant pumps are vertical, single stage, centrifugal, shaft seal pumps. All pressure bearing parts of the reactor coolant pumps were analyzed in accordance with Article 4 of the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition. This includes the casing, the main flange, and the main flange bolts.

Table 2.2.2.6-1 of the PBN EPU license amendment request provides a summary of the CUFs for the reactor coolant pumps. All CUFs are below the acceptance criteria of 1.0. As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUFs for the reactor coolant pumps remain valid for the SPEO.

Pressurizers

The PBN pressurizers are vertical, cylindrical vessels with hemispherical top and bottom heads, constructed of carbon steel with internal surfaces clad with austenitic stainless steel. Each PBN pressurizer was designed, fabricated, inspected and tested in accordance with the 1965 Edition of Section III of the ASME Boiler and Pressure Vessel Code.

Table 2.2.2.7-1 of the PBN EPU license amendment request provides a summary of the CUFs for the pressurizers. All CUFs are below the acceptance criteria of 1.0. As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUFs for the pressurizers remain valid for the SPEO.

Reactor Vessel Internals

The reactor internals and core support structures were designed and built prior to the implementation of Subsection NG of the ASME Code, and therefore, a plant-specific stress report on the reactor internals was not required. The structural integrity of the PBN reactor internals design has been ensured by analyses performed on both generic and plant-specific bases to meet the intent of the ASME Code.

A series of evaluations/assessments were performed on reactor vessel internals components for the EPU project. Table 2.2.3-3 of the PBN EPU license amendment request provides a summary of the CUFs for the reactor vessel internals components. All CUFs are below the acceptance criteria of 1.0. As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUFs for the reactor vessel internals components remain valid SPEO.

Pressurizer Surge Lines

The pressurizer surge lines have been analyzed to the requirements of ASME Code, Section III, Class I, 1986 with addenda in response to NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification” (Reference ML031220290). The analysis includes a fatigue evaluation that considers the effects of thermal stratification.

Section 2.2.2.1 of the PBN EPU license amendment request provides an evaluation of the EPU impact on the surge line fatigue analysis. The evaluation concluded that the EPU has no adverse impact on either the thermal stratification or the fatigue analysis for the pressurizer surge line, and the results remain acceptable for the 60-year PEO. As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUFs for the pressurizer surge lines remain valid for the SPEO.

Pressurizer Spray Piping

Fatigue usage of the pressurizer spray piping was originally calculated to evaluate the effect of thermal stratification for piping evaluated in response to NRC Bulletin 88-08, “Thermal Stresses in Piping Connected to Reactor Coolant System,” (Reference 1.6.29). For license renewal, PBN calculated a 60-year CUF using refined fatigue analysis techniques and thermal stratification cycle assumptions, and a CUF value of 0.277 was established for the limiting PBN Unit 1 piping location.

For SLR, the analysis has been projected to the end of the subsequent period of extended operation. Stratification cycles are conservatively projected based on thermocouple data with a leaking spray control valve that is assumed to leak throughout 80 years of plant operation. This results in a CUF value of 0.369 for SLR. Due to the conservatism applied to this analysis, cycle monitoring is not required for this location.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) and 10 CFR 54.21(c)(1)(iii)

The fatigue analysis for the pressurizer piping spray piping has been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

The remaining ASME Section III, Class 1 fatigue calculations remain valid for the SPEO. The results demonstrate that the number of assumed design cycles will not be exceeded in 80 years of plant operation. To ensure the design cycles remain bounding in the Class 1 component fatigue analyses, the Fatigue Monitoring AMP (Section B.2.2.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits.

Table 4.3.1-1
80-Year Projected Cycles – PBN Units 1 and 2

Item	Transient	Current Cycles Year-end 2019 Unit 1	Current Cycles Year-end 2019 Unit 2	80-year Projection	Design Allowable Cycles	80-year Allowable Cycles
1	10% Step Load Decrease	25	30	44	2000	100
2	10% Step Load Increase	0	1	2	2000	20
3	50% Step Load Decrease	46	20	66	200	100
4	Accumulator Safety Injection	4	1	7	89	8
5	Auxiliary Spray Actuation	0	0	0	10	2
6	HPSI Injection	2	0	4	89	4
7	Inadvertent Accumulator Blowdown	0	0	0	4	2
8	Inadvertent RCS Depressurization	0	0	0	20	2
9	Loss of Charging Flow	16	17	34	60	50
10	Loss of Letdown Flow	20	17	46	200	75
11	Pressurizer Cooldown	78	61	115	200	120
12	Pressurizer Heatup	79	62	116	200	120
13	Primary Side Hydrostatic Test	1	2	3	5	3
14	Primary Side Leak Test	36	38	57	94	60
15	Primary to Secondary Leak Test	2	9	14	27	15
16	RCS Cooldown	79	62	118	200	120
17	RCS Heatup	80	63	119	200	120
18	RPV Safety Injection	0	0	0	89	2
19	Reactor Trip	68	52	107	300	120
20	Refueling	49	46	77	80	80
21	Relief Valve Actuation	1	3	7	100	8
22	Secondary to Primary Leak Test	38	33	57	128	60
23	Trip Due to Loss of RCP	1	2	4	100	4
24	Unit Loading 5%/min	1691	1806	2478	11600	8000 (Note 1)
25	Unit Unloading 5%/min	1544	1670	2295	11600	8000 (Note 1)
26	FW Cycling at Hot Standby	NC	NC	N/A	2000	Not provided
27	Boron Concentration Eq.	NC	NC	N/A	23360	Not provided
28	Loss of Load (Trip)	NC	NC	N/A	80	80
29	Loss of Power (Trip)	NC	NC	N/A	40	40
30	Loss of Flow (Trip)	NC	NC	N/A	80	80
31	Turbine Roll Test	NC	NC	N/A	10	10
32	Control Rod Drop	NC	NC	N/A	N/A	80
33	Excessive FW Flow	NC	NC	N/A	N/A	30
34	OBE	NC	NC	N/A	N/A	10

Notes

1 – Specific 80-year allowable cycles are limited to the following values for specific RCS components due to environmentally-assisted fatigue (EAF) values presented in Table 4.3.4-1:

(a) CRDM upper latch housings are limited to 2700 loading and unloading cycles at 5%/min

(b) Vessel flanges are limited to 5000 loading and unloading cycles at 5%/min

(c) The fatigue crack growth (FCG) analysis of longitudinal flaws in reactor coolant loop cast austenitic stainless steel piping components (Reference 4.8.15) utilizes a limit of 3,000 loading and unloading cycles.

Table Footnotes

NC = Not Counted
N/A = Not applicable - there is no basis for computing the upper bound
UFSAR Transient 'Steady State Fluctuations' omitted; small fluctuations do not cause fatigue usage
Transients 19 and 23 constitute the 400 Reactor Trip Transients in the UFSAR
UFSAR Transient 16 'Reactor Coolant Pipe Break' is a Faulted Event, which is not counted
UFSAR Transient 17 'Steam Line Break' is a Faulted Event, which is not counted

4.3.2. ASME Code, Section III, Class 1 Component Fatigue Waivers

TLAA Description:

A detailed fatigue evaluation is not required if components conform to the waiver of fatigue requirements of ASME Code, Section III. Fatigue waivers that consider transient cycles that occur over the life of the plant constitute TLAAs. ASME Code, Class 1 component fatigue waivers are discussed in this section.

The following equipment have sub-components that conform to the waiver of fatigue requirements in ASME Code, Section III.

- Steam generators
    - Shop installed weld tube plugs
    - Ribbed mechanical tube plugs
    - Tube wall undercut

TLAA Evaluation

To address the metal fatigue TLAAs identified as part of SLR, the CLB fatigue waivers for the ASME Code, Section III, Class 1 components were determined by reviewing the TLAA identification work performed for initial license renewal and updating it to incorporate any fatigue-related work that has been performed to-date.

Section 2.2.2.5.9 of the PBN extended power uprate (EPU) license amendment request (Reference ML110750120) indicates that the three steam generator sub-components listed above conform to the waiver of fatigue requirements in ASME Section III. The six fatigue exemption conditions in N-415.1 of Reference 1.6.30 were evaluated for these sub-components in lieu of an explicit calculation of the usage factor. The fatigue exemption evaluations for these sub-components considers the normal and upset EPU design transients. The EPU design transients are consistent with the PBN CLB design transients listed in Table 4.3.1-1.

In order to document that the CLB fatigue waivers remain valid and bounding through the SPEO, transient cycle projections for 80 years of operation were compared against the CLB cycles for each transient. As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound 80 years of plant operations. Therefore, the fatigue waivers for Class 1 components remain valid for the SPEO. In order to ensure the design cycles, remain bounding in the ASME Code, Section III Class 1 component fatigue waivers, the Fatigue Monitoring AMP (Section B.2.2.1) will track cycles for the applicable transients and ensure corrective action is taken prior to potentially exceeding fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The ASME Code, Section III, Class 1 component fatigue waivers will be managed by the Fatigue Monitoring AMP through the SPEO. The Fatigue Monitoring AMP will monitor the transient cycles and severities which are the inputs to the fatigue waiver analyses and require action prior to exceeding design limits that would invalidate their conclusions.

4.3.3. Metal Fatigue of Non-Class 1 Components

TLAA Description

The PBN reactor coolant system primary loop piping and balance-of-plant piping systems within the scope of subsequent license renewal are designed to the requirements of ANSI B31.1, Power Piping. The exception is the PBN Units 1 and 2 pressurizer surge lines which have been analyzed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Subsection NB and are addressed in Section 4.3.1.

Piping and components designed in accordance with ANSI B31.1 design rules are not required to have an explicit analysis of cumulative fatigue usage, but cyclic loading is considered in a simplified manner in the design process. The code first requires prediction of the overall number of thermal and pressure cycles expected during the lifetime of these components. Then a stress range reduction factor is determined for that number of cycles using a Table from the applicable design code, similar to Table 4.3.3-1 below. If the total number of cycles is 7,000 or less, the stress range reduction factor is 1.0, which when applied, would not reduce the allowable stress value.

The assessments of fatigue for these piping systems are considered to be implicit fatigue analyses since they are based upon cycles anticipated for the life of the component, and are therefore, TLAAs requiring evaluation for the SPEO.

TLAA Evaluation

Design requirements in ANSI B31.1 assume a stress range reduction factor to provide conservatism in the piping design to account for fatigue due to thermal cyclic operation. The cyclic qualification of the piping per ANSI B31.1 is based on the number of equivalent full temperature cycles as listed in Table 4.3.3-1.

Table 4.3.3-1
Stress Range Reduction Factors for ANSI B31.1 Piping

Number of Equivalent Full Temperature Cycles	Stress Range Reduction Factor
7,000 and less	1.0
7,000 to 14,000	0.9
14,000 to 22,000	0.8
22,000 to 45,000	0.7
45,000 to 100,000	0.6
100,000 and over	0.5

The reduction factor is 1.0 provided the number of anticipated cycles is limited to 7000 equivalent full temperature cycles for piping and tubing. A review of the ANSI B31.1 piping within the scope of SLR was performed in order to identify those systems that operate at elevated temperature and to establish a conservative number of projected cycles based on 80 years of operation. Typically, these piping and tubing systems are subject to continuous steady-state operation and experience temperature cycling only during plant heatup and cooldown, during plant transients, or during periodic testing.

From the EPRI Report TR-104534, “Fatigue Material Handbook” Volume 2, Section 4 (Reference 4.8.16) and the EPRI Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools (Reference ML12335A508), piping and tubing systems subject to thermal fatigue due to temperature cycling are described as,

> *“For initial screening, systems in which the fluid temperature can vary more than 200°F in austenitic steel components and more than 150°F in carbon and low alloy steel components are potentially of concern for fatigue due to thermal transients. Thus, carbon steel systems or portions of systems with operating temperatures less than 220°F and stainless steel systems or portions of systems with operating temperatures less than 270°F may generally be excluded from such concerns, since room temperature represents a practical minimum exposure temperature for most plant systems.”*

All non-Class 1 mechanical systems within the scope of the PBN SLRA were initially screened for the TLAA associated with metal fatigue. PBN SLR mechanical systems with maximum fluid temperatures below the limits specified above are not considered to be susceptible metal fatigue and a TLAA is not applicable. Therefore, any PBN non-Class 1 mechanical system or portions of systems with operating temperatures above 220°F are conservatively evaluated for metal fatigue. The non-Class 1 piping and tubing systems requiring evaluation for the metal fatigue SLR are listed in Table 4.3.3-2 below.

Once a system is established to operate at a temperature above 220°F, system operating characteristics are established, and a determination is made as to whether the system is expected to exceed 7000 full temperature cycles in 80 years of operation. In order to exceed 7000 cycles a system would be required to heatup and cooldown approximately once every four days. For the systems that are subjected to elevated temperatures above the fatigue threshold, an evaluation was performed to determine a conservative number of projected full temperature cycles for 80 years of plant operation. These projections, which are presented in Table 4.3.3-2, indicate that 7000 thermal cycles will not be exceeded for 80 years of operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The ANSI B31.1 allowable stress calculations remain valid for the SPEO. The results demonstrate that the number of assumed thermal cycles will not be exceeded in 80 years of plant operation.

Table 4.3.3-2
Projected Number of Full Temperature Cycles

Description	Conservative Basis for Cycle Projection	Projected Cycles for 80 years
Auxiliary Feedwater	The turbine driven AFW pumps are normally in standby service and are started quarterly by in-service testing procedures. This would equate to 4 times per year x 80 years = 320 cycles leaving significant margin to 7000 cycles to account for any additional pump starts in support of plant startup and shutdown.	Less than 7,000 cycles
Chemical and Volume Control	Normal charging and letdown during the reactor coolant system power operation is at steady state temperature. Conservatively assume 4 thermal and loading cycles for the chemical and volume control system per year.	Less than 7,000 cycles
Emergency Power	PBN surveillance requirements require the emergency diesel generators to be started once per 31 days (12 times per year). SR 3.8.1.5, 3.8.1.6 and 3.8.1.7 require the emergency diesel generators to be started once per 18 months (assume once per year). Total cycles = 13 cycles per year x 80 years = 1040 cycles.	Less than 7,000 cycles
Feedwater and Condensate	Feedwater and condensate transients relative to power cycle operation (plant heatup and cooldown) consistent with reactor coolant system transients from UFSAR Table 4.1-8.	Less than 7,000 cycles
Fire Protection	Fire pump diesel engine cycles only during pump testing, which occurs weekly . 52 cycles/year x 80 years = 4,160 cycles.	Less than 7,000 cycles
Heating Steam	Cycles based on seasonal heating. Conservatively assume 85 cycles per year (80 years x 85/year = 6,800 cycles)	Less than 7,000 cycles

Table 4.3.3-2
Projected Number of Full Temperature Cycles

Description	Conservative Basis for Cycle Projection	Projected Cycles for 80 years
Main and Auxiliary Steam	Main and auxiliary steam transients relative to power cycle operation (plant heatup and cooldown) consistent with reactor coolant system transients from FSAR Table 4.1-8.	Less than 7,000 cycles
Plant Sampling	A specific hot leg sample evaluation was performed for PBN license renewal and it resulted in a total of 6702 cycles for 60 years of operation. The critical assumption in the evaluation that would be used for the additional 20 year operating period is thermal cycling of the hot leg sample line occurs only 10 times per year. This would result in an additional 200 cycles for the hot line sample line, resulting in a total number of 6902 cycles for the 80-year SPEO.	Less than 7,000 cycles
Reactor Coolant System	Reactor coolant system thermal and loading cycle limits are provided in FSAR Table 4.1-8. Plant heatup and cooldown limits are 200 cycles each.	Less than 7,000 cycles
Residual Heat Removal	Residual heat removal system piping is heated during shutdowns and startups. Assume four thermal cycles per heatup and cooldown each plant shutdown.	Less than 7,000 cycles
Safety Injection	Portions of safety injection system piping is connected to the reactor coolant system and is subjected to thermal and loading cycle limits provided in FSAR Table 4.1-8. Safety injection pump testing temperature less than 200ºF.	Less than 7,000 cycles
Waste Disposal	Conservatively assume high temperature portions of the liquid waste management system are cycles once per week. Total cycles = 52 cycles per year x 80 years = 4,160 cycles.	Less than 7,000 cycles

4.3.4. Environmentally Assisted Fatigue

TLAA Description

As outlined in Section X.M1 of NUREG-2191 and Section 4.3 of NUREG-2192, the effects of the reactor water environment on cumulative usage factor (CUF) must be examined for a set of sample critical components for the plant. This sample set includes the locations identified in NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components” (Reference ML031480219) and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR-6260. These additional limiting locations are identified through an environmental fatigue screening evaluation. The environmentally-assisted fatigue (EAF) screening process consisted of two methods. The first method made use of existing fatigue usage values for the ASME Code, Section III components. The second method consisted of the EPRI common basis stress evaluation (CBSE) method for estimating fatigue usage for the ANSI B31.1 piping without fatigue values per EPRI Report 1024995, “Environmentally-Assisted Fatigue Screening: Process and Technical Basis for Identifying EAF Limiting Locations” (Reference 4.8.17). The EAF screening evaluation reviewed the CLB fatigue evaluations for all ASME Code, Section III reactor coolant pressure boundary components and ANSI B31.1 piping, including the NUREG/CR-6260 locations, to determine the lead indicator (also referred to as sentinel) locations for EAF.

TLAA Evaluation

To support subsequent license renewal, calculations were prepared to document the evaluations of environmentally-assisted fatigue for ASME Code, Section III reactor coolant system (RCS) pressure boundary components and piping and determine fatigue-sensitive locations for comparison and ranking. These evaluations are for subsequent license renewal purposes and do not amend the existing design reports. The TLAA evaluation is presented separately for ASME Code, Section III components and ANSI B31.1 piping. Discussion of the screening approaches used for the ASME Code, Section III components and ANSI B31.1 piping are provided below due to slight differences in the screening approach used. As a result of the EAF screening evaluation, there were other locations found that could be more limiting than the NUREG/CR-6260 locations (see Westinghouse LTR-SDA-II-20-05-P/NP, Revision 2, “Environmentally-Assisted Fatigue Screening Results for Point Beach Unit 1 and Unit 2 Safety Class 1 Primary Equipment,” (Reference 4.8.18) and SIA Report No. 2000088.402, “Environmentally-Assisted Fatigue Evaluation for 80 Years of Plant Operation for Point Beach Nuclear Units 1 and 2,” (Reference 4.8.19).

<u>ASME Code, Section III Component Screening</u>

In the EAF screening process for ASME Code, Section III components with existing fatigue usage values, all of the applicable ASME Code, Section III components that are susceptible to EAF were reviewed and categorized by component. These reactor coolant pressure boundary components include the reactor vessels, control rod drive mechanisms (CRDMs), pressurizers, and steam generators. Screening F_{en} factors were developed for each component so that CUF_{en} can be calculated and compared. The methodology outlined in NUREG/CR-6909, Revision 1, “Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, Final Report” (Reference 1.6.31) was used for stainless steels, carbon and low-alloys steels, and Ni-Cr-Fe alloys.

Conservative values were chosen for each of the F_{en} input parameters, including sulfur content, service temperature, strain rate, and dissolved oxygen (DO). The values for these F_{en} input parameters with justification for their selection were included in Westinghouse letter report LTR-SDA-II-20-05-NP and supporting calculations. The primary objective of the EAF component screening evaluation was to compare locations within a specific RCS component to determine the sentinel locations with respect to EAF. Locations within each component were compared on the bases of common transients and common stress analysis methods to determine the most limiting location(s). Any location that is not part of the ASME Code, Section III reactor coolant pressure boundary was removed from consideration. Other locations not in contact with primary coolant were also excluded.

The screening CUF_{en} was determined conservatively by applying the appropriate environmental fatigue correction factor (F_{en}) for the material calculated using the methods from Revision 1 of NUREG-6909 considering the pressurized water reactor (PWR) environment. Using this screening process, the following component location screening CUF_{en} values were determined to be less than 1.0 and required no further evaluation:

- Reactor vessel inlet nozzle support pad
- Reactor vessel outlet nozzle support pad
- Reactor vessel inlet nozzle
- Reactor vessel outlet nozzle
- Pressurizer upper head
- Pressurizer upper head instrument nozzle
- Pressurizer lower head instrument nozzle and heater well

The remaining components in Table 4.3.4-1 required further evaluation as their screening CUF_{en} values exceeded 1.0. Details of the evaluations of these component locations are provided below.

ANSI B31.1 Piping Screening

The original Code of record for PBN RCS piping is USAS (ANSI) B31.1, "Power Piping Code," which uses a stress range reduction factor and does not calculate fatigue usage values for this piping. Over the operating history of Units 1 and 2, CUFs at several of the ANSI B31.1 piping locations have been calculated to the requirements of ASME Code, Section III, as follows:

- The pressurizer surge lines have been analyzed to the requirements of ASME Code, Section III, Class I, 1986 with addenda in response to NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification” (Reference ML031220290).

- To evaluate the effect of thermal stratification on the pressurizer spray piping, including the auxiliary spray line connection, fatigue analyses were performed for each PBN unit. The analyses were performed in accordance with the requirements of NRC Bulletin 88-08, “Thermal Stresses in Piping Connected to Reactor Coolant Systems”.

- A PBN plant-specific simplified ASME Code Section III fatigue analyses has been performed for the charging nozzles in 2003 in support of initial license renewal.

- A PBN plant-specific simplified ASME Code Section III fatigue analyses has been performed for the safety injection (accumulator) nozzles in 2003 in support of initial license renewal.

- A PBN plant-specific simplified ASME Code Section III fatigue analyses has been performed for the residual heat removal (RHR) tees in 2003 in support of initial license renewal.

Not enough information exists to complete a screening evaluation using CUF values to determine which PBN ANSI B31.1 piping locations are the most fatigue sensitive. Therefore, another means is needed to evaluate whether other piping locations may be more limiting. The plants most similar in design to PBN are other Westinghouse 2-loop (W 2-loop) pressurized water reactors (PWRs). A review of NUREG/CR-5640 (Reference 1.6.32) identifies the Westinghouse 2-loop plants as:

- Kewaunee
- R. E. Ginna
- Point Beach
- Prairie Island

As documented in report 2000088.402, SIA has performed EAF evaluations for each of these Westinghouse 2-loop plants. A review of SI files indicates that none of the EAF evaluations for these plants included locations other than those considered in NUREG/CR-6260. That's to be expected, since the guidance for considering locations that may be more limiting was not issued until after these plants submitted their original LRAs. In support of the recent Surry SLRA, SI performed EAF screening using a EPRI Common Basis Stress Evaluation (CBSE) approach included in EPRI Report 1024995 that considered all other Class 1 piping. The EPRI CBSE process uses a simplified version of Class 1 piping analysis rules where thermal transient stresses are estimated using closed form solutions, and other stresses are calculated based on existing piping equations. The advantage of the EPRI CBSE process is that the same formulas and level of detail are used to calculate stress range and estimated fatigue usage so that results at different points can be compared.

Although Surry is a Westinghouse 3-loop plant design, the Code of record for its RCS piping is also USAS (ANSI) B31.1. EAF screening for Surry identified that the applicable NUREG/CR-6260 piping locations and the pressurizer spray piping were the sentinel locations. This provides reasonable assurance that the original four (4) NUREG-6260 piping locations for the PBN LR and the pressurizer spray piping constitute the ANSI B31.1 piping sentinel locations for PBN SLR. These locations are:

- Hot leg surge nozzle
- Charging nozzle
- Accumulator safety injection nozzle
- RHR tee
- Pressurizer spray piping

In lieu of EAF screening calculations, PBN elected to perform detailed fatigue analyses for these five (5) piping locations. Details of these analyses can be found in the further evaluation section below.

Further Evaluation of ASME Section III Component EAF

The EAF further evaluations for ASME Section III components were performed using the guidelines in NRC Regulatory Guide 1.207, “Guidelines for Evaluating the Effects of Light-Water Reactor Water Environments in Fatigue Analyses of Metal Components” (Reference ML16315A130) and the F_{en} equations in Revision 1 of NUREG/CR-6909. These evaluations utilized the analyses of record (AORs) and design fatigue curves in Section A.2.1 of Revision 1 of NUREG/CR-6909 to derive a CUF, and then utilized the F_{en} equations in Section A.2 of Revision 1 of NUREG/CR-6909 to derive a CUF_{en}. The goal of these further EAF evaluations was to calculate a CUF_{en} below 1.0 through typical linear elastic fatigue analysis techniques. Conservatisms in the stress and fatigue analyses in the AORs were identified and removed, if possible, in the CUF calculations. For component locations with low CUFs, the CUF_{en} was calculated by applying the maximum F_{en} to the CUF. For component locations that could not accept this conservative method, strain rate dependent F_{en} values were calculated for significant fatigue pairs using the modified rate approach. In general, the EAF further component evaluations can be categorized into two groups:

1. Simplified EAF Evaluations

   The AOR CUF was reduced by applying the design fatigue curves in Section A.2.1 of Revision 1 of NUREG/CR-6909 and implementing reduced cycles for specific transients. The CUF_{en} was calculated by applying the maximum F_{en} to the CUF.

2. Detailed EAF Evaluations

   The AOR CUF was recalculated by applying the design fatigue curves in Section A.2.1 of Revision 1 of NUREG/CR-6909, implementing reduced cycles for specific transients, and implementing additional refinements related to the identification of stress cycles and application of more appropriate fatigue strength reduction factors (FSRFs). The CUF_{en} was calculated by applying the maximum F_{en} to the CUF or using the modified rate approach.

   With the exception of the pressurizer lower head, additional details of the ASME Section III sentinel component EAF evaluations can be found in the Westinghouse LTR-SDA-II-20-08-P/NP, “Environmentally-Assisted Fatigue Evaluation Results for the Point Beach Unit 1 and Unit 2 Primary Equipment Sentinel Locations for Subsequent License Renewal,” (Reference 4.8.20) and supporting calculations.

   Westinghouse LTR-SDA-II-20-13-P/NP, Revision 2, “Environmentally Assisted Fatigue Evaluation Results for the Point Beach Unit 1 and Unit 2 Pressurizer Lower Head for Subsequent License Renewal”, (Reference 4.8.21) summarizes the methodology and results of EAF evaluation performed for the PBN pressurizer lower head for the SPEO. The letter report and associated calculation performs an EAF evaluation, including insurge/outsurge transient effects, for the limiting pressurizer lower head locations using the guidelines in NRC Regulatory Guide 1.207 and the EAF penalty factor (F_{en}) equations in NUREG/CR-6909, Revision 1. The goal of this evaluation is to demonstrate that the pressurizer lower head EAF results for a reference plant SPEO are applicable to PBN Units 1 and 2. To accomplish this, a comparative evaluation was performed for the applicable inputs required for an EAF evaluation of both the representative plant and PBN pressurizer lower head. The comparative evaluation concluded that representative plant pressurizer design, ASME Code year, piping moment loads, RCS transients, insurge/outsurge transient severity, and future plant operation are applicable to PBN.

Results of the ASME Section III component EAF further evaluation calculations are presented in Table 4.3.4-1. In addition to the CUF_{en} values, the original AOR CUF, the CUF developed for SLR, and a brief summary of the conservatisms removed from the AOR for ASME Code, Section III components are also provided in Table 4.3.4-1.

Further Evaluation of ANSI B31.1 Piping EAF

Piping analyses previously performed for the 60-year NUREG-6260 locations were used as inputs to the SLR EAF calculations. These calculations provide the transient loads, component materials, evaluated locations, and fatigue analysis results used as input to the SLR EAF calculation. Conservative values are chosen for each of the F_{en} input parameters, including sulfur content, service temperature, strain rate, and dissolved oxygen (DO). The values for these F_{en} input parameters with justification for their selection are included in SIA Report No. 2000088.402 and supporting calculation 2000088.310P-REDACTED/PR0PRIETARY, “EAF Refined Analyses (Charging Nozzle, Hot Leg Surge Nozzle, SI Nozzle, SI/RHR Tee)”, (Reference 4.8.22).

The EAF evaluation of fatigue usage associated with the thermal stratification measured in the pressurizer spray line in response to NRC Bulletin 88-08, as described above in Section 4.3.1, is extended for 80 years of operation in Revision 3 to SIA calculation PBCH-03Q-301, “Evaluation of Thermal Stratification Due to Valve Leakage” (Reference 4.8.23). Since publication of Revision 1 of this calculation, the NRC has issued NUREG-6909 Revision 1, which requires that the effects of reactor water environments be considered in calculating fatigue. Although the location that is the subject of this calculation is not designed to ASME Class 1 criteria (NB-3650), the environmental fatigue penalty factors, and the associated fatigue curve in air contained in the NUREG, are used in assessing environmentally assisted fatigue usage for this location. The methodology, assumptions, and results of the EAF analysis are included in calculation PBCH-03Q-301.

Results of the SLR piping EAF further evaluation calculations are presented in Table 4.3.4-1.

Fatigue Management

The effects of fatigue on the intended functions of the ASME Code, Section III components and B31.1 piping components listed in Table 4.3.4-1 that have a calculated CUF_{en} value less than 1.0 will be managed by the Fatigue Monitoring AMP (Section B.2.2.1) through the use of cycle counting. The Fatigue Monitoring AMP will monitor the transient cycles which are the inputs to the EAF evaluations and require action prior to exceeding design limits that would invalidate their conclusions.

For the pressurizer spray nozzle safe ends, the effects of fatigue will be managed by application of the In-service Inspection program (ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1) during the SPEO based on results of flaw tolerance evaluation conducted in accordance with the guidance of ASME Code, Section XI, Nonmandatory, Appendix L. NUREG-2192 permits inspections as a management method for fatigue as long as a flaw tolerance evaluation is performed to determine the acceptable time between inspections. The ASME Code, Section XI, Appendix L crack growth evaluation is used in conjunction with calculated allowable flaw sizes to determine the required inspection interval for a postulated flaw in the piping at the bounding location. For a postulated initial flaw, crack growth is simulated until the flaw has reached the allowable flaw depth or the end of the SPEO, whichever comes first.

The purpose of the flaw tolerance evaluation is to establish an appropriate inspection frequency that is consistent with the typical 10-year in-service inspection program for the pressurizer spray nozzle safe ends. The inputs used for the pressurizer spray nozzle safe ends evaluation (geometry, transient cycles and definitions, material properties, piping loads, etc.) bound both Units 1 and 2. The ASME Code, Section XI, Appendix L flaw tolerance evaluation consists of postulating a hypothetical inside surface axial and circumferential flaw.

The 2007 Edition of ASME Section XI is the current edition specified for the PBN Units 1 and 2 in-service inspection program. The 2017 Edition of Section XI has the latest NRC and ASME approved Appendix L methodology and is used for the PBN Appendix L analysis. The 2007 Edition of Section XI Appendix C methodology used for flaw tolerance analyses are the same except that the 2017 Edition extends the applicability of Appendix C to nominal pipe sizes greater than 1 (see Section IWB-3641 of Section XI) and the 2017 Edition includes different equations for Z-factors for nominal pipe sizes less than 4 (see Section C-6330 of Section XI).

The Section XI Appendix L flaw tolerance evaluation consists of calculating the maximum allowable end-of-evaluation (EOE) period flaw size and determining the allowable operating period for a postulated flaw to grow via fatigue crack growth (FCG) to the maximum allowable EOE period flaw size. ASME Section XI Appendix L-3212 requires the postulated initial flaw depth to be no smaller than the applicable acceptance standards in Table IWB-3410-1 using a flaw shape (a/l) equal to 0.167 (or aspect ratio, AR = 6). Since the analysis locations for the pressurizer spray nozzle are at the stainless steel safe end and safe-end-to-pipe welds, Section IWB-3514 is used to determine the initial flaw size for welds and adjacent base metal in austenitic piping material.

The postulated flaws used in the flaw tolerance evaluation are inside surface axial and circumferential flaws with aspect ratios (AR, flaw length/flaw depth) determined based on ASME Section XI Appendix L. Due to the nature of fatigue mechanisms, several small fatigue cracks may initiate, coalesce, and then grow like an equivalent long single crack. ASME Section XI Appendix L calculates the required aspect ratio to be used in the flaw tolerance evaluation to consider the effects of fatigue cracking. The evaluation of postulated inside surface flaws conservatively covers evaluations for embedded flaws and outside surface flaws, as the stress intensity factors for inside surface flaws are more limiting than embedded and outside surface flaws.

The primary crack growth mechanism for flaws within the spray nozzle/weld is fatigue crack growth. Crack growth due to primary water stress corrosion cracking (PWSCC) growth does not need to be investigated since the base metals (stainless steel piping and nozzles) and stainless steel weld material have a low susceptibility to stress corrosion cracking. The fatigue crack growth rate and the applicable stress intensity factor equations are needed to perform a FCG analysis. The FCG rate for stainless steel in a water environment is based on ASME Section XI Code Case N-809 (Reference 4.8.24). The 2016 Edition of API-579-1 (Reference 4.8.25) is used for the stress intensity factor calculations.

The results of the pressurizer spray nozzle safe ends ASME Code, Section XI, Appendix L evaluation are provided in Table 4.3.4-2. As can be seen from the table, the most limiting result is for the axial flaw case at location ASN 2 which demonstrates an acceptable period of at least 12 years. These results provide assurance that flaws will not grow to an unacceptable size between inservice examinations based on conservative Section XI Appendix L methodology. Additional details of the Appendix L analysis are provided in Westinghouse letter report LTR-SDA-20-064-P/NP (Reference 4.8.26).

In-service inspections of the ASME Code, Section XI, Appendix L pressurizer spray nozzle safe ends piping will be performed every ten years during the SPEO. The ASME Code, Section XI, Appendix L inspections will be conducted by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP.

For the steam generator primary side tube location, the effects of fatigue will be managed by the Steam Generators AMP (Section B.2.3.10). Consistent with the GALL-SLR Report AMP XI.M19, the steam generator tubes will be volumetrically examined such that fatigue cracks will be detected, and corrective actions will be initiated as appropriate to maintain the intended functions.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) and 10 CFR 54.21(c)(1)(iii)

In the case of the pressurizer spray piping, the environmentally-assisted fatigue analysis has been projected to the end of the period of extended operation. Stratification cycles are conservatively projected based on thermocouple data with a leaking spray control valve that is assumed to leak throughout 80 years of plant operation. Due to the conservatism applied to this analysis, cycle monitoring is not required.

The effects of environmentally-assisted fatigue on the intended functions of ASME Code, Section III components and B31.1 piping that contact reactor coolant will be managed by the Fatigue Monitoring AMP (Section B.2.2.1), the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1), and the Steam Generators AMP (Section B.2.3.10) through the SPEO.

Table 4.3.4-1: Sentinel Locations

Table 4.3.4-1: Sentinel Locations

RCS Component	Location	Material	CUF AOR	CUF SLR	F_{en}	CUF_{en}	Analysis Method	Fatigue Management Method
Reactor Vessel	CRDM Nozzle	Ni-Cr-FE Alloy	[ ]	[ ]	[ ]	0.946	The Ni-Cr-Fe alloy design fatigue curve in Section A.2.1 of Ref. 4.3.4.5 was applied. Refinements were made regarding the identification of stress cycles and application of more appropriate FSRFs. The cycles were reduced for the following transients: • Unit Loading 5%/min: 2,700 cycles • Unit Unloading 5%/min: 2,700 cycles The design cycles from the AOR were considered for all other transients.	Fatigue Monitoring (B.2.2.1) AMP - Cycle Counting
	Vessel Flange	Low-Alloy Steel	[ ]	[ ]	[ ]	0.985	The low alloy steel (LAS) design fatigue curve in Section A.2.1 of Ref. 4.3.4.5 was applied. The cycles were reduced for the following transients: • Unit Loading 5%/min: 5,000 cycles • Unit Unloading 5%/min: 5,000 cycles The design cycles from the AOR were considered for all other transients.	Fatigue Monitoring (B.2.2.1) AMP - Cycle Counting

Table 4.3.4-1: Sentinel Locations

RCS Component	Location	Material	CUF		F_{en}	CUF_{en}	Analysis Method	Fatigue Management Method
			AOR	SLR				
CRDM	Upper Latch Housing	Stainless Steel	[ ]	[ ]	[ ]	0.713	The stainless steel (SS) design fatigue curve in Section A.2.1 of Ref. 4.3.4.5 was applied. Refinements were made regarding the identification of stress cycles and application of more appropriate FSRFs. The design cycles from the AOR were considered for all transients.	Fatigue Monitoring (B.2.2.1) AMP - Cycle Counting
Pressurizer Upper Head/Shell	Spray Nozzle	Stainless Steel	0.871	N/A	N/A	N/A	ASME Section XI, Appendix L	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP
	Safety and Relief Nozzle	Carbon Steel	[ ]	[ ]	[ ]	0.953	The LAS design fatigue curve in Section A.2.1 of Ref. 4.3.4.5 was applied. The design cycles from the AOR were considered for all transients	Fatigue Monitoring (B.2.2.1) AMP - Cycle Counting

Table 4.3.4-1: Sentinel Locations

RCS Component	Location	Material	CUF		F_{en}	CUF_{en}	Analysis Method	Fatigue Management Method
			AOR	SLR				
Pressurizer Lower Head	Nozzle to Safe End Weld	Carbon Steel	N/A(1)	[ ]	[ ]	0.6577	An ASME NB-3200 analysis was performed for SLR. The insurge/outsurge transient event distribution was refined by incorporating plant specific data and operational trends.	Fatigue Monitoring (B.2.2.1) AMP - Cycle Counting
	Nozzle to Safe End Weld	Stainless Steel	5.0E-7	[ ]	[ ]	0.9648		
Steam Generator	Tubes	Ni-Cr-FE Alloy	0.948 (U1) 0.223 (U2)	N/A	N/A	N/A	N/A	Steam Generators (B.2.3.10) AMP
	Primary Chamber, Tubesheet, and Stub Barrel Complex (U2)	Low-Alloy Steel	[ ]	[ ]	[ ]	0.967	The LAS design fatigue curve in Section A.2.1 of Ref. 4.3.4.5 was applied. The cycles were reduced for the following transients: • Unit Loading 5%/min: 10,015 cycles which exceeds the Fatigue Management AMP allowable cycle limit of 8000 cycles • Feedwater Cycling at Hot Standby: 24,815 cycles The design cycles from the AOR were considered for all other transients.	Fatigue Monitoring (B.2.2.1) AMP - Cycle Counting

Table 4.3.4-1: Sentinel Locations

RCS Component	Location	Material	CUF		F_{en}	CUF_{en}	Analysis Method	Fatigue Management Method
			AOR	SLR				
Piping	Hot Leg Surge Nozzle	Stainless Steel	0.0383	0.1487	6.51	0.9685	ASME NB-3200 analysis assuming design and projected allowable cycles from Table 4.3.1-1.	Fatigue Monitoring (B.2.2.1) AMP - Cycle Counting
	Charging Nozzle	Stainless Steel	0.1182	0.1619	4.41	0.7149	ASME NB-3200 analysis assuming design allowable cycles from Table 4.3.1-1.	Fatigue Monitoring (B.2.2.1) AMP - Cycle Counting
	Accumulator Safety Injection Nozzle	Stainless Steel	0.0072	0.0173	5.39	0.0930	ASME NB-3600 analysis assuming design allowable cycles from Table 4.3.1-1.	Fatigue Monitoring (B.2.2.1) AMP - Cycle Counting
	RHR / SI Tee	Stainless Steel	0.0142	0.0332	2.28	0.0758	ASME NB-3600 analysis assuming design allowable cycles from Table 4.3.1-1.	Fatigue Monitoring (B.2.2.1) AMP - Cycle Counting
	Pressurizer Spray Piping	Stainless Steel	0.369	0.154	4.83	0.744	ASME NC-3600 implicit analysis using Mark I approach.	None Required

Notes

(1) No fatigue usage result for this location was reported in the original PBN license renewal application.

Table 4.3.4-2: ASME Section XI Appendix L Results

Analysis Section Number (ASN)	Flaw Configuration	Appendix L Calculated Aspect Ratio	Acceptable Standards Flaw Size Table Section XI Table IWB-3410-1 (a/t)	Final Flaw Size (a/t)	Maximum Allowable End-of-Evaluation Flaw Size (a/t)	Allowable Operating Period (Years)
ASN 2	Axial Flaw	69.1	0.1214	0.171	0.173	12
	Circumferential Flaw	50	0.1214	0.168	0.170	22
ASN 3	Axial Flaw	42.0	0.1361	0.379	0.383	53
	Circumferential Flaw	42.6	0.1361	0.249	0.530	80

4.4. ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRIC EQUIPMENT

TLAA Description

Thermal, radiation, and cyclical aging analyses of plant electrical and instrumentation components, developed to meet 10 CFR 50.49 requirements, have been identified as TLAAs. The NRC has established environmental qualification (EQ) requirements in 10 CFR 50.49 and 10 CFR Part 50, Appendix A, Criterion 4. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of in- service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a design basis accident such as a loss-of-coolant accident (LOCA), high energy line break (HELB), or main steam line break (MSLB).
10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification. Aging evaluations for electrical components in the EQ Program that involve time-limited assumptions defined by the current operating term of 60 years have been identified as TLAAs for SLR because the EQ aging evaluations meet the criteria in 10 CFR 54.3. Aging evaluations that qualify components for shorter periods, and that therefore require refurbishment, replacement, or extension of their qualified life, are not TLAAs.

TLAA Evaluation

The PBN Environmental Qualification of Electric Equipment AMP described in Section B.2.2.4 meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of components within the scope of the Environmental Qualification of Electric Equipment AMP, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics and the environmental conditions to which the components could be subjected during their service life.

10 CFR 50.49(e)(5) contains provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect component functional capability. 10 CFR 50.49(e)(5) also requires replacement or refurbishment of components not qualified for the current license term prior to the end of designated life, unless additional life is established through ongoing qualification. 10 CFR 50.49(f) establishes four methods of demonstrating qualification for aging and accident conditions.
10 CFR 50.49(k) permits different qualification criteria to apply based on plant and component vintage and 10 CFR 50.49(l) requires replacement equipment to be qualified in accordance with the provisions of 10 CFR 50.49. Supplemental environmental qualification regulatory guidance for compliance with these different qualification criteria is provided in the DOR Guidelines, “Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors” (Reference 4.8.27), NUREG-0588, Revision 1, “Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment” (Reference 1.6.33), and Regulatory Guide 1.89, Revision 1, “Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants” (Reference 1.6.34).

Compliance with 10 CFR 50.49 provides reasonable assurance that the component can perform its intended functions during accident conditions after experiencing the effects of in- service aging. The Environmental Qualification of Electric Equipment AMP manages component thermal, radiation, and cyclical aging, as applicable, through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation.

The Environmental Qualification of Electric Equipment AMP, which implements the requirements of 10 CFR 50.49, as further defined and clarified by NUREG-0588 and Regulatory Guide 1.89 is viewed as an aging management program for SLR under 10 CFR 54.21(c)(1)(iii). Reanalysis of an aging evaluation to extend the qualifications of components is performed on a routine basis as part of the Environmental Qualification of Electric Equipment AMP. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). The disposition of the TLAAs in accordance with 10 CFR 54.21(c)(1)(iii), which states that the effects of aging will be adequately managed for the SPEO, is chosen based on the fact the Environmental Qualification of Electric Equipment AMP will manage the aging effects of the electrical and instrumentation components associated with the EQ TLAAs.

NUREG-2192 states that the staff evaluated the Environmental Qualification of Electric Equipment program (10 CFR 50.49) and determined that it is an acceptable aging management program to address environmental qualification according to 10 CFR 54.21(c)(1)(iii). The evaluation referred to in NUREG-2192 contains sections on "EQ Component Reanalysis Attributes, Evaluation, and Technical Basis" is the basis of the description provided below.

Component Reanalysis Attributes

The reanalysis of an aging evaluation is normally performed to extend the qualification by reducing 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 the Environmental Qualification of Electric Equipment AMP. While a component life-limiting condition may be due to thermal, radiation, or cyclical aging, the 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, 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 quality assurance program requirements, which require the verification of assumptions and conclusions. As previously 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

PBN EQ equipment purchased prior to February 22, 1983 is qualified in accordance with the Division of Operating Reactors (DOR) Guidelines as clarified by Regulatory Guide

1.89, Revision 1. EQ equipment purchased on or after February 22, 1983 is qualified in accordance with 10 CFR 50.49 or Regulatory Guide 1.89, Revision 1. This includes equipment/spare parts purchased as a replacement for installed equipment previously qualified to DOR Guidelines, unless there are documented "sound reasons to the contrary" for the use of replacement equipment in lieu of upgrading.

Thermal Considerations - The EQ Program uses the same analytical models in the reanalysis of an aging evaluation as those previously applied during the prior evaluation. The component qualification temperatures were calculated for 80 years using the Arrhenius method, as described in EPRI NP-1558, “A Review of Equipment Aging Theory and Technology” (Reference 4.8.28). As thermal aging is governed by the ambient temperature to which the device is exposed, the Environmental Qualification of Electric Equipment AMP conservatively assumes a normal ambient temperature of ≤ 135°F for areas inside containment, and a normal ambient temperature of ≤ 104.5°F for areas outside containment. The 135°F inside containment represents the (worst case) normal ambient temperature in the reactor coolant area. Other areas inside containment (e.g. outside the secondary shield wall) assume normal ambient temperature of 105°F.

For additional conservatism, a temperature rise of 10.4°C is added to these assumed operating temperatures for continuous duty power cables to account for ohmic heating.

There is no significant change in the normal service temperature for general areas inside containment due to the Extended Power Uprate (EPU power level of 1811 MWt) condition (Reference ML110450159). The staff verified that the normal operating temperatures due to EPU will continue to be bounded by the temperatures used in PBN’s EQ analyses. Furthermore, the staff verified that the EPU post-accident peak temperature will continue to be bounded by the peak temperature used in PBN’s EQ analyses.

Radiation Considerations - The impact of Extended Power Uprate (EPU power level of 1811 MWt) on the PBN normal gamma and neutron radiation levels for inside containment has been evaluated. The normal radiation dose for outside containment has not changed due to power uprate conditions. The normal neutron radiation dose for locations outside containment is insignificant considering the shielding provided by the containment structure. The normal 80-year total integrated radiation dose inside containment varies with the area.

Due to EPU, which was approved in 2011, the core power level increased from 1540 MWt to 1800 MWt. Analyzed core power is currently 1811 MWt which includes 0.6 percent measurement uncertainty. This represents an increase of approximately 17.6 percent in core thermal power. Since Unit 1 went online in October 1970 and Unit 2 in March 1973, the 80-year normal operation doses are conservatively estimated reflecting the pre EPU dose rate and the EPU level for both units. The radiation EQ for safety-related electrical equipment inside containment is based on the radiation environment expected to exist during normal operations, post-LOCA conditions, and the resultant cumulative radiation doses. The staff found that the total integrated radiation doses (normal plus accident) for EPU conditions would not adversely affect the qualification of equipment inside containment.

The effect of the EPU on environmental conditions inside and outside containment on the qualification of electrical equipment was evaluated. Electrical equipment will continue to meet the relevant requirements of 10 CFR 50.49 following implementation of the EPU.

To verify that the bounding radiation values are acceptable for the SPEO, 80-year integrated dose values were determined and then the established accident dose added to the 80-year normal operating dose for the component to determine the 80-year total integrated dose (TID). This was then compared to the qualification value established by the current EQ analysis. If the qualification value exceeded the 80-year TID, then no additional evaluation was required.

Wear Cycle Considerations - The wear cycle aging effect is only applicable to active components, such as but not limited to, solenoid valves, motor-operated valves, transmitters, and connectors that are periodically disconnected. Established wear cycle limits were compared to the projected wear cycles for 80 years to demonstrate acceptability for the SPEO.

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 per the Environmental Qualification of Electric Equipment AMP. Temperature data used in an aging evaluation should 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 were justified. Similar methods of reducing excess conservatism in the component service conditions applied in prior aging evaluations can be used for radiation and cyclical aging.

Underlying Assumptions

The Environmental Qualification of Electric Equipment AMP 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 Action

Per the Environmental Qualification of Electric Equipment AMP, the reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component is refurbished, replaced, or re-qualified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner such that sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful. For EQ equipment with a qualified life less than the required design life of the plant, "ongoing qualification" is a method of long-term qualification involving additional testing. Ongoing qualification or retesting, as described in IEEE Standard 323-1974, Section 6.6, "Ongoing Qualification," paragraphs (1) and (2), is not currently considered a viable option and PBN has no plans to implement it. If this option becomes viable in the future, ongoing qualification or retesting will be performed in accordance with accepted EQ industry and regulatory standards.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging on the intended function(s) will be adequately managed for the SPEO. The Environmental Qualification of Electric Equipment AMP has been demonstrated to be capable of programmatically managing the qualified lives of the electrical and instrumentation components falling within the scope of the program for subsequent license renewal. The continued implementation of the Environmental Qualification of Electric Equipment AMP provides reasonable assurance that the aging effects will be managed and that EQ components will continue to perform their intended functions for the SPEO.

4.5. CONCRETE CONTAINMENT TENDON PRESTRESS

TLAA Description

The PBN Units 1 and 2 containment buildings are post-tensioned, reinforced concrete structures composed of vertical cylinder walls and a shallow dome on a pile supported reinforced concrete base slab. The cylinder walls are provided with vertical tendons and horizontal hoop tendons. The dome is provided with three groups of tendons oriented 120-degrees apart.

Over time, the containment prestressing forces decrease due to relaxation of the steel tendons and due to creep and shrinkage of the concrete. The containment tendon prestressing forces were calculated during the original design considering the magnitude of the tendon relaxation and concrete creep and shrinkage over the 40-year life of the plant. The PBN Concrete Containment Unbonded Tendon Prestress AMP (Section B.2.2.3) and the PBN ASME Section XI, Subsection IWL AMP (Section B.2.3.30) perform periodic surveillances of individual tendon prestressing values.

Predicted force values are calculated for each tendon prior to the surveillances to estimate the magnitude of the tendon relaxation and concrete creep and shrinkage for the given surveillance period. The prestressing forces are measured and plotted, and trend lines are developed, to ensure the average tendon group prestressing values remain above the respective minimum required values (MRVs) until the next scheduled surveillance. The predicted force values and regression analyses, utilizing actual measured tendon forces, are used to evaluate the acceptability of the containment structure to perform its intended function over the current 60-year life of the plant, and therefore, are TLAAs requiring evaluation for the SPEO.

TLAA Evaluation

The prestress of containment tendons decreases over time as a result of seating of anchorage losses, elastic shortening of concrete, creep of concrete, shrinkage of concrete, relaxation of prestressing steel, and friction losses. At the time of initial licensing, the magnitude of the prestress losses throughout the life of the plant was predicted and the estimated final effective preload at the end of 40 years was calculated for each tendon type. The final effective preload was then compared with the minimum required preload to confirm the adequacy of the design. The estimated final effective prestressing force at the end of plant life was projected to 60 years during the original license renewal process. Described below is the summary of the evaluation for 80 years.

The methodology used in this SLR TLAA follows the same methodology used in developing TLAA calculation for the original license renewal. The upper bound and lower bound tendon lift-off force curves for the 80-year lifetime are developed in accordance with Regulatory Guide 1.35 (Reference 1.6.35) and Regulatory Guide 1.35.1 (Reference 1.6.36). An allowance of 1 percent is considered for wire breakage in developing the lower bound lift-off force curves, consistent with the original license renewal evaluation. The lower bound tendon lift-off force curves developed in the original license renewal evaluation are adjusted to account for 1 percent allowance for wire breakage at 80 years of operating life.

The PBN Prestressed Concrete Containment Tendon Surveillance Program is a confirmatory program that monitors the loss of prestressing forces in containment tendons throughout the life of the plant, including the SPEO. This program consists of an assessment of the results of the tendon prestressing force measurements performed in accordance with ASME Section XI, Subsection IWL (Reference 1.6.37). As part of this program, tendon forces were measured for selected tendons in Unit 1 and Unit 2 periodically. Detensioned/retensioned tendons are no longer considered to be statistically relevant to the original tendon population and excluded from the regression analysis conservatively. Regression analyses are performed to obtain the trendlines which fit the measured tendon force data most accurately in order to forecast the tendon forces for the extended 80-year operating life. The post-tensioning system of the PBN containment structure consists of dome tendons, hoop tendons, and vertical tendons. For each tendon group in PBN Unit 1 and Unit 2, the measured tendon force data, the trendlines obtained from regression analyses, the upper and lower bound lift-off force curves and the minimum required tendon forces are plotted in log-linear time-force plots for the 80-year SPEO.

As shown in Figures 4.5-1 through 4.5-6, the trendlines developed using past surveillance data remain above the lower bound curves for all PBN Unit 1 and Unit 2 dome, hoop, and vertical tendons during the entire 80-year SPEO. The tendon forces used to develop these plots are tabulated in Tables 4.5-2 through 4.5-7.

Table 4.5-1 provides a summary of the forecasted tendon forces and concludes all tendon forces for 80-year SPEO are higher than the minimum required tendon forces. Furthermore, the lower bound curves for all dome, hoop and vertical tendons remain above the minimum required tendon forces. Consequently, the trendlines remain above the minimum required tendon forces for all containment tendons.

Table 4.5-1
Containment Tendon Force Summary

FORECAST YEARS	FORECASTED FORCE BASED ON REGRESSION (KIPS)					
	UNIT 1 TENDONS			UNIT 2 TENDONS		
	DOME	HOOP	VERTICAL	DOME	HOOP	VERTICAL
40 YEARS	638.60	636.44	661.46	628.68	634.13	647.92
60 YEARS	634.27	632.40	657.99	620.50	626.87	642.60
80 YEARS	631.20	629.54	655.53	614.69	621.71	638.83
MINIMUM REQUIRED TENDON FORCE (KIPS)	606.60	594.00	621.00	606.60	594.00	621.00

In conclusion, the predicted tendon prestressing forces at 80 years of service life will be adequate to maintain the structural integrity of the containment post-tensioning system.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The concrete containment tendon prestress analysis has been projected to the end of the SPEO. Additionally, the Concrete Containment Unbonded Tendon Prestress AMP (Section B.2.2.3) and ASME Section XI, Subsection IWL AMP (Section B.2.3.30) will manage the effects of aging related to prestress forces on the containment tendon prestressing system so that the intended function will be adequately managed for the SPEO.

Table 4.5-2
Tendon Force Data for Unit 1 Dome Tendons

FORECAST YEAR	FORECASTED FORCE BASED ON REGRESSION (KIPS)	LOWER BOUND LIFT-OFF FORCE (KIPS)	UPPER BOUND LIFT-OFF FORCE (KIPS)	MINIMUM REQUIRED FORCE (KIPS)
1	677.99	637.20	689.40	606.60
3	666.26	631.11	683.31	606.60
5	660.80	628.28	680.48	606.60
10	653.40	624.43	676.63	606.60
15	649.07	622.18	674.38	606.60
20	646.00	620.59	672.79	606.60
25	643.62	619.35	671.55	606.60
30	641.67	618.34	670.54	606.60
35	640.03	617.48	669.68	606.60
40	638.60	616.74	668.94	606.60
45	637.34	616.09	668.29	606.60
50	636.22	615.51	667.71	606.60
55	635.20	614.98	667.18	606.60
60	634.27	614.50	666.70	606.60
65	633.42	614.05	666.25	606.60
70	632.63	613.64	665.84	606.60
75	631.89	613.26	665.46	606.60
80	631.20	612.90	665.10	606.60

Note

The minimum required force is the force used in the design of the containment and does not include the 1 percent allowance for wire breakage. The lower bound lift-off force at 80 years does include this 1 percent allowance.

Table 4.5-3
Tendon Force Data for Unit 1 Hoop Tendons

FORECAST YEAR	FORECASTED FORCE BASED ON REGRESSION (KIPS)	LOWER BOUND LIFT-OFF FORCE (KIPS)	UPPER BOUND LIFT-OFF FORCE (KIPS)	MINIMUM REQUIRED FORCE (KIPS)
1	673.14	624.60	687.60	594.00
3	662.21	618.51	681.51	594.00
5	657.13	615.68	678.68	594.00
10	650.23	611.83	674.83	594.00
15	646.20	609.58	672.58	594.00
20	643.33	607.99	670.99	594.00
25	641.11	606.75	669.75	594.00
30	639.30	605.74	668.74	594.00
35	637.77	604.88	667.88	594.00
40	636.44	604.14	667.14	594.00
45	635.27	603.49	666.49	594.00
50	634.22	602.91	665.91	594.00
55	633.27	602.38	665.38	594.00
60	632.40	601.90	664.90	594.00
65	631.61	601.45	664.45	594.00
70	630.87	601.04	664.04	594.00
75	630.19	600.66	663.66	594.00
80	629.54	600.30	663.30	594.00

Note

The minimum required force is the force used in the design of the containment and does not include the 1 percent allowance for wire breakage. The lower bound lift-off force at 80 years does include this 1 percent allowance.

Table 4.5-4
Tendon Force Data for Unit 1 Vertical Tendons

FORECAST YEAR	FORECASTED FORCE BASED ON REGRESSION (KIPS)	LOWER BOUND LIFT-OFF FORCE (KIPS)	UPPER BOUND LIFT-OFF FORCE (KIPS)	MINIMUM REQUIRED FORCE (KIPS)
1	693.00	651.60	695.70	621.00
3	683.60	645.51	689.61	621.00
5	679.24	642.68	686.78	621.00
10	673.31	638.83	682.93	621.00
15	669.84	636.58	680.68	621.00
20	667.38	634.99	679.09	621.00
25	665.47	633.75	677.85	621.00
30	663.92	632.74	676.84	621.00
35	662.60	631.88	675.98	621.00
40	661.46	631.14	675.24	621.00
45	660.45	630.49	674.59	621.00
50	659.55	629.91	674.01	621.00
55	658.73	629.38	673.48	621.00
60	657.99	628.90	673.00	621.00
65	657.30	628.45	672.55	621.00
70	656.67	628.04	672.14	621.00
75	656.08	627.66	671.76	621.00
80	655.53	627.30	671.40	621.00

Note

The minimum required force is the force used in the design of the containment and does not include the 1 percent allowance for wire breakage. The lower bound lift-off force at 80 years does include this 1 percent allowance.

Table 4.5-5
Tendon Force Data for Unit 2 Dome Tendons

FORECAST YEAR	FORECASTED FORCE BASED ON REGRESSION (KIPS)	LOWER BOUND LIFT-OFF FORCE (KIPS)	UPPER BOUND LIFT-OFF FORCE (KIPS)	MINIMUM REQUIRED FORCE (KIPS)
1	703.10	637.20	689.40	606.60
3	680.94	631.11	683.31	606.60
5	670.63	628.28	680.48	606.60
10	656.65	624.43	676.63	606.60
15	648.47	622.18	674.38	606.60
20	642.66	620.59	672.79	606.60
25	638.16	619.35	671.55	606.60
30	634.48	618.34	670.54	606.60
35	631.37	617.48	669.68	606.60
40	628.68	616.74	668.94	606.60
45	626.30	616.09	668.29	606.60
50	624.18	615.51	667.71	606.60
55	622.25	614.98	667.18	606.60
60	620.50	614.50	666.70	606.60
65	618.88	614.05	666.25	606.60
70	617.39	613.64	665.84	606.60
75	615.99	613.26	665.46	606.60
80	614.69	612.90	665.10	606.60

Note

The minimum required force is the force used in the design of the containment and does not include the 1 percent allowance for wire breakage. The lower bound lift-off force at 80 years does include this 1 percent allowance.

Table 4.5-6
Tendon Force Data for Unit 2 Hoop Tendons

FORECAST YEAR	FORECASTED FORCE BASED ON REGRESSION (KIPS)	LOWER BOUND LIFT-OFF FORCE (KIPS)	UPPER BOUND LIFT-OFF FORCE (KIPS)	MINIMUM REQUIRED FORCE (KIPS)
1	700.26	624.60	687.60	594.00
3	680.57	618.51	681.51	594.00
5	671.41	615.68	678.68	594.00
10	658.99	611.83	674.83	594.00
15	651.72	609.58	672.58	594.00
20	646.56	607.99	670.99	594.00
25	642.56	606.75	669.75	594.00
30	639.29	605.74	668.74	594.00
35	636.53	604.88	667.88	594.00
40	634.13	604.14	667.14	594.00
45	632.02	603.49	666.49	594.00
50	630.13	602.91	665.91	594.00
55	628.43	602.38	665.38	594.00
60	626.87	601.90	664.90	594.00
65	625.43	601.45	664.45	594.00
70	624.10	601.04	664.04	594.00
75	622.87	600.66	663.66	594.00
80	621.71	600.30	663.30	594.00

Note

The minimum required force is the force used in the design of the containment and does not include the 1 percent allowance for wire breakage. The lower bound lift-off force at 80 years does include this 1 percent allowance.

Table 4.5-7
Tendon Force Data for Unit 2 Vertical Tendons

FORECAST YEAR	FORECASTED FORCE BASED ON REGRESSION (KIPS)	LOWER BOUND LIFT-OFF FORCE (KIPS)	UPPER BOUND LIFT-OFF FORCE (KIPS)	MINIMUM REQUIRED FORCE (KIPS)
1	696.30	651.60	695.70	621.00
3	681.89	645.51	689.61	621.00
5	675.19	642.68	686.78	621.00
10	666.10	638.83	682.93	621.00
15	660.78	636.58	680.68	621.00
20	657.01	634.99	679.09	621.00
25	654.08	633.75	677.85	621.00
30	651.69	632.74	676.84	621.00
35	649.67	631.88	675.98	621.00
40	647.92	631.14	675.24	621.00
45	646.38	630.49	674.59	621.00
50	644.99	629.91	674.01	621.00
55	643.74	629.38	673.48	621.00
60	642.60	628.90	673.00	621.00
65	641.55	628.45	672.55	621.00
70	640.58	628.04	672.14	621.00
75	639.68	627.66	671.76	621.00
80	638.83	627.30	671.40	621.00

Note

The minimum required force is the force used in the design of the containment and does not include the 1 percent allowance for wire breakage. The lower bound lift-off force at 80 years does include this 1 percent allowance.

Figure 4.5-1 – Time-Dependent Tendon Force Curves for Unit 1 Dome Tendons

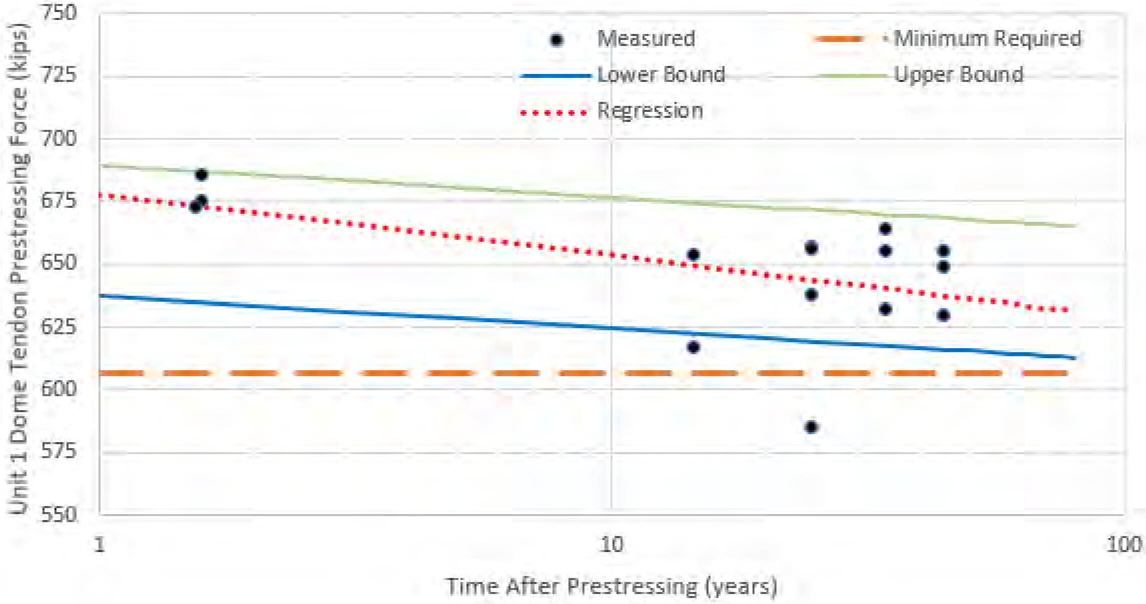


Figure 4.5-2 – Time-Dependent Tendon Force Curves for Unit 1 Hoop Tendons

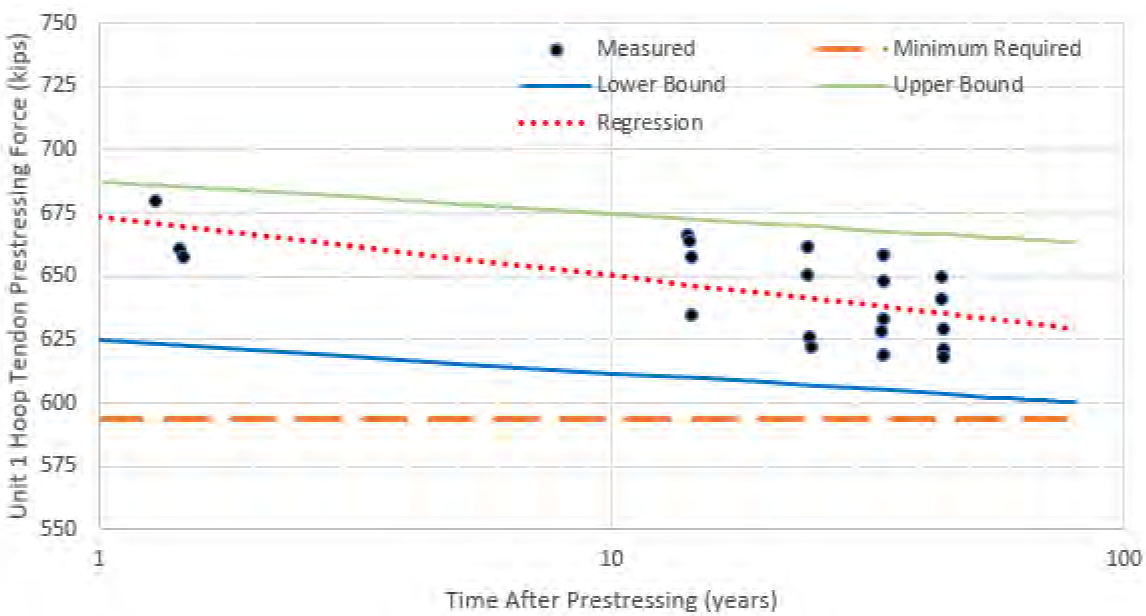


Figure 4.5-3 – Time-Dependent Tendon Force Curves for Unit 1 Vertical Tendons

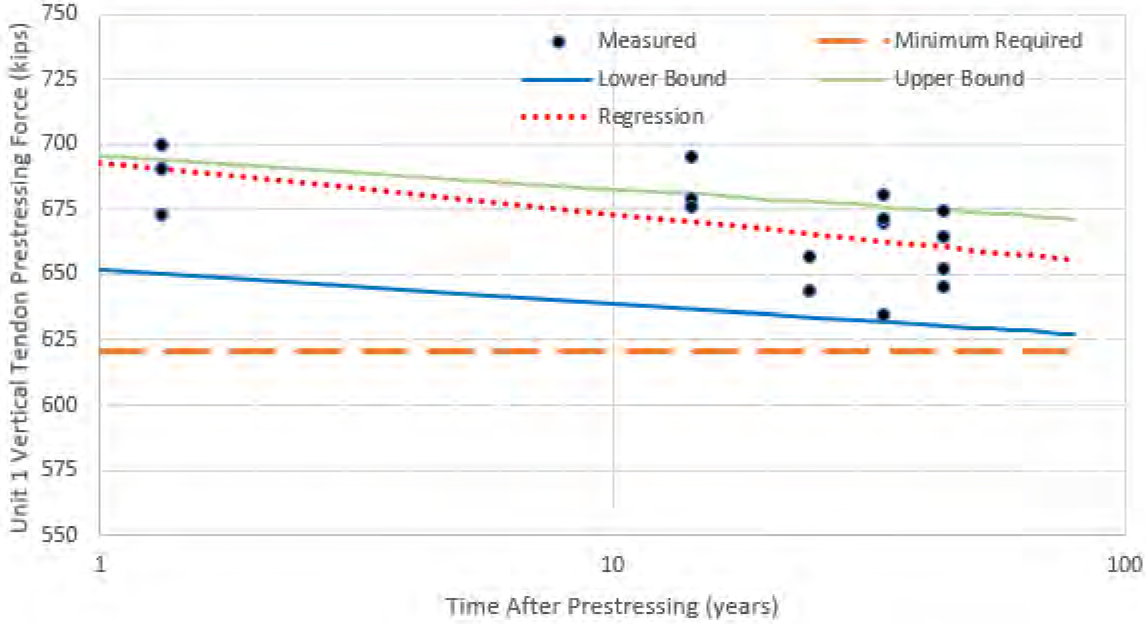


Figure 4.5-4 – Time-Dependent Tendon Force Curves for Unit 2 Dome Tendons

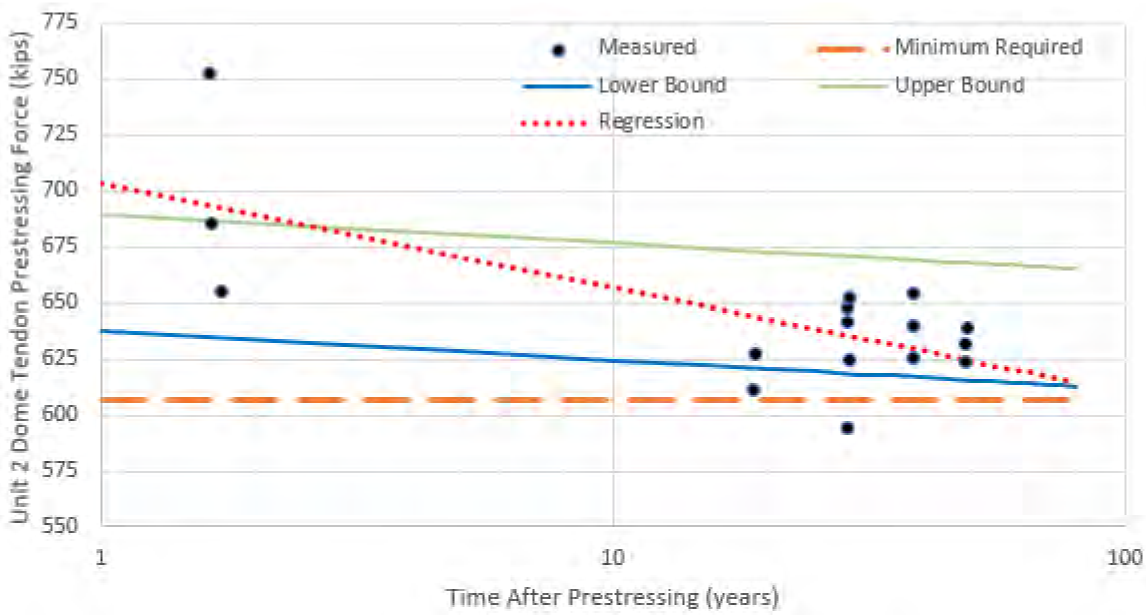


Figure 4.5-5 – Time-Dependent Tendon Force Curves for Unit 2 Hoop Tendons

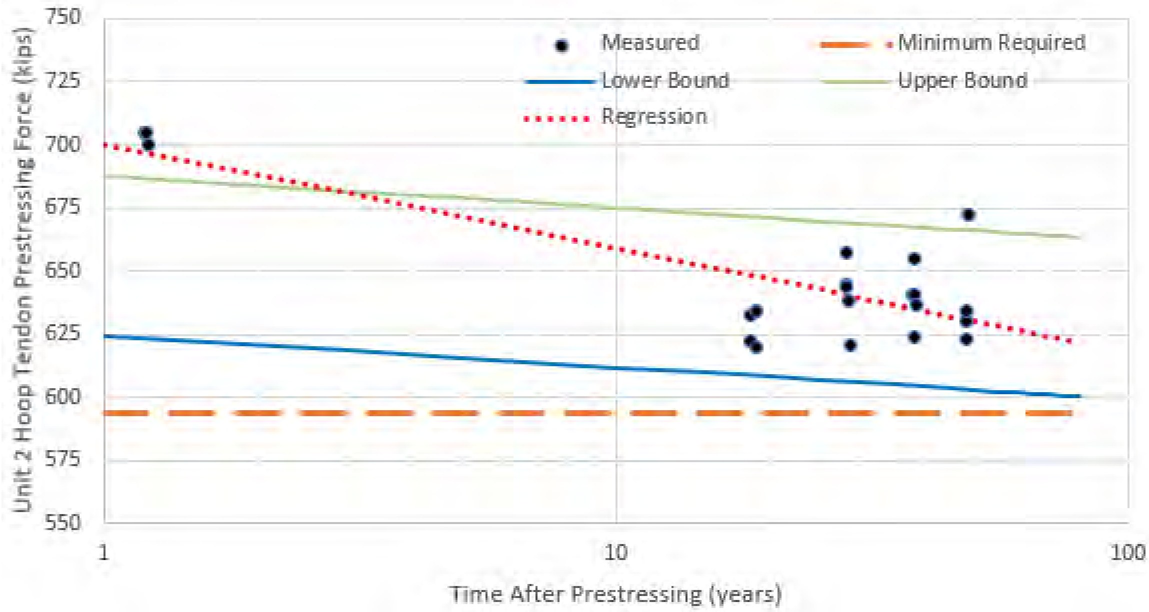
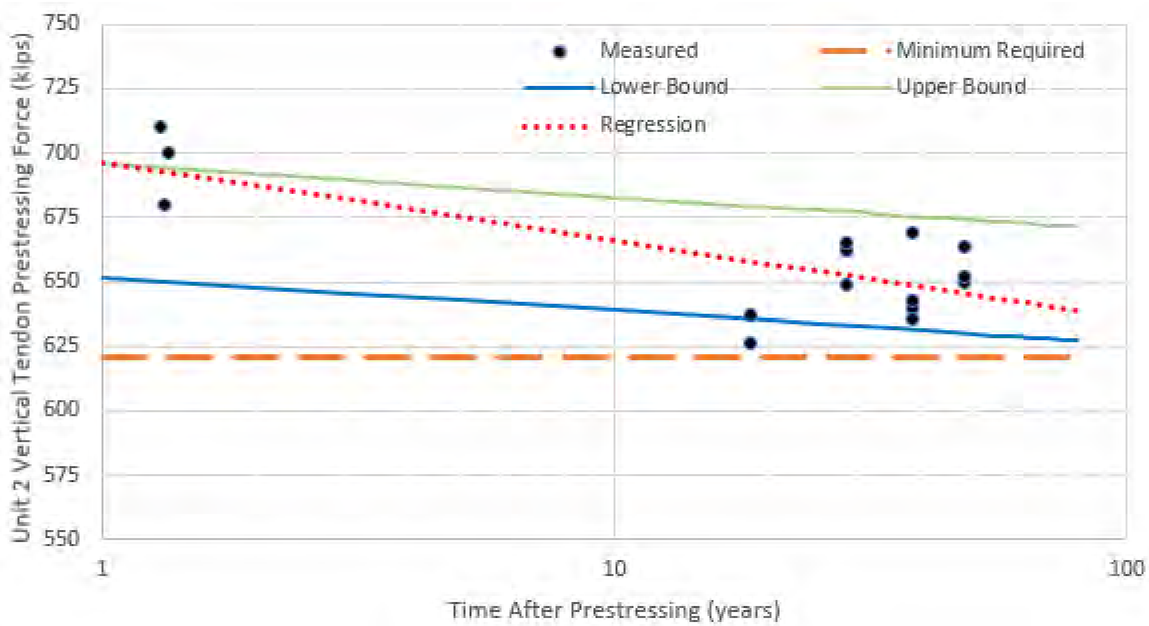


Figure 4.5-6 – Time-Dependent Tendon Force Curves for Unit 2 Vertical Tendons



4.6. CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATIONS FATIGUE

TLAA Description

The interior of each PBN containment is lined with welded steel plates to provide an essentially leak-tight barrier. Design criteria are applied to the liner plate to assure that the specified allowed containment leak rate is not exceeded under design basis accident conditions. The following fatigue loads, as described in UFSAR Section 5.1.2.2, were considered in the design of the liner plate and are considered a time-limited aging analysis for the purposes of license renewal:

1. Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is 60 for the current plant life of 60 years.
2. Thermal cycling due to containment interior temperature varying during the startup and shutdown of the reactor system. The number of cycles for this loading is assumed to be 500.
3. Thermal cycling due to the design basis accident is assumed to be one cycle.
4. Thermal load cycles in the piping system are somewhat isolated from the liner plate penetrations by concentric sleeves between the pipe and the liner plate. The attachment sleeves are designed in accordance with ASME Boiler and Pressure Vessel Code, Section III, fatigue considerations. All penetrations are reviewed for a conservative number of cycles to be expected during the plant life.

Each of the above items has been evaluated for the SPEO.

TLAA Evaluation

For item one, the number of thermal cycles due to annual outdoor temperature variations was increased from 60 to 80 for the SPEO. The effect of this increase is insignificant in comparison to the assumed 500 thermal cycles due to containment interior temperature varying during heatup and cooldown of the reactor coolant system (RCS). The 500 thermal cycles includes a margin of 300 thermal cycles above the 200 allowable RCS design heatup and cooldown cycles, which is sufficient margin to accommodate the additional 20 cycles of annual outdoor temperature variation. Therefore, this loading condition is considered valid for the SPEO as it is enveloped by item two.

For item two, the assumed 500 thermal cycles was evaluated based on the more limiting heatup and cooldown design cycles (transients) for the major components of the RCS. As indicated in Table 4.1-8 of the PBN UFSAR, the major components of the RCS were designed to withstand 200 heatup and cooldown cycles. This number of maximum RCS heatup and cooldown design cycles is conservative enough to envelop the projected cycles for the SPEO. Therefore, the original containment liner plate fatigue analysis for 500 heatup and cooldown cycles is considered valid for the SPEO.

For item three, the assumed value for thermal cycling due to the design basis accident remains valid. No maximum design basis accident has occurred to date and none is expected, therefore, this assumption is considered valid for the SPEO.

For item four, the design of the containment piping penetrations was previously reviewed as part of the original PBN license renewal application. The liner plate (including piping penetration extension sleeves) incorporated the design guidance of the ASME Boiler and Pressure Vessel Code, Section III, 1965 edition, Nuclear Vessels, Article 4, Paragraphs; N-412(m), N-414.5, N-412(n), and N-415.1, Figures N-414, and N-415(A); and Table N-413. The containment penetrations conform to the applicable sections of ASA N6.2-1965, "Safety Standard for the Design, Fabrication, and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors." In addition, penetration strains were limited per the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Article 4, 1965 edition. The containment penetration head fittings were designed, fabricated, inspected, and tested in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class B, 1968 edition and all addenda.

The main steam, feedwater, blowdown, and letdown systems are the only piping systems penetrating the containment that could contribute significant thermal loading on the liner plate. Due to the higher operating temperature, the main steam piping penetration was considered bounding and was therefore evaluated for fatigue through the PEO in SI calculation PBCH-06Q-301 (Reference 4.8.29). ASME Code, Section III, N-415.1 states that a fatigue analysis is not required, provided the service loading of the vessel or component meets all of the following six specified conditions:

(i) Atmospheric to operating pressure cycles
(ii) Normal service pressure fluctuations
(iii) Temperature difference - startup and shutdown
(iv) Temperature difference - normal service
(v) Temperature difference - dissimilar materials
(vi) Mechanical loads

The analysis of the main steam piping penetration sleeve and the sleeve end fitting connecting the pressure piping to the sleeve verified that the six conditions of ASME Code, Section III, Subsection A, N 415.1, 1965, are satisfied for the PEO and a fatigue analysis of the piping penetrations is not required.

The Reference 4.8.29 analysis was evaluated for applicability to the SPEO. Section 2.0 of the analysis lists the temperature assumptions for the main steam piping penetration as follows:

- Hot shutdown: 550°F
- Full Power: 520°F
- Containment at Startup: 90°F

Review of Table 1-1 of the PBN extended power uprate (EPU) license amendment (Reference ML110750120) concludes that these main steam temperature assumptions are applicable to the SPEO.

The Reference 4.8.29 analysis also assumes a number of pressure cycles for each of the six conditions specific above. Conditions (i) and (iii) assume 400 operating pressure cycles which is bounded by the 200 plant heatup and cooldown cycles established for the reactor coolant system. Conditions (ii) and (iv) assume 17,354 normal service pressure fluctuations (14,500 loading/unloading, 2200 load increase/decrease, 400 reactor trips, and 254 tests). This number of normal service pressure fluctuations is significantly greater than the 80-year projected cycles listed in Table 2.1-3 of Structural Integrity Associated Report No. 2000088.401. Conditions (v) and (vi) represent bounding cycle values on the applicable fatigue curve and are applicable for the SPEO. Therefore, the Reference 4.8.29 analysis remains applicable for the SPEO and a fatigue analysis of the piping penetrations is not required.

PBN has been unable to locate the original fatigue analysis or confirm if a fatigue waiver exists for the PBN containment penetrations other than piping penetrations, piping penetrations with dissimilar metal welds, and for the expansion's joints of the containment structure reactor fuel transfer tube. Therefore, consistent with NUREG-2192, Table 3.5-1, Item 3.5-1, 027, cracking due to cyclic loading of non-piping containment penetrations (i.e. personnel airlocks, equipment hatch, personnel hatch, electrical penetrations, piping penetrations with dissimilar metal welds, and the expansions joints of the containment structure fuel transfer tube will be managed by the ASME Section XI, Subsection IWE AMP (Section B.2.3.29) and periodic supplemental surface examinations incorporated into and consistent with the frequency of the 10 CFR Part 50, Appendix J AMP (Section B.2.3.32).

TLAA Disposition: 10 CFR 54.21(c)(1)(i) and 10 CFR 54.21(c)(1)(iii)

The fatigue analyses associated with the containment liner plate and piping penetrations have been evaluated and determined to remain valid for the SPEO. The fatigue analyses associated with the containment personnel airlocks, equipment hatch, personnel hatch, electrical penetrations, piping penetrations with dissimilar metal welds, and expansions joints of the containment structure fuel transfer tube will be managed by the ASME Section XI, Subsection IWE AMP and the 10 CFR Part 50, Appendix J AMP.

4.7. OTHER PLANT-SPECIFIC TLAAs

4.7.1. Leak-Before-Break of Reactor Coolant System Loop Piping

TLAA Description

In 1996, Westinghouse performed a plant specific primary loop piping leak-before-break (LBB) analysis for PBN Units 1 and 2. The results of the analysis were documented in WCAP-14439 (Reference 4.8.30). In 2003, the LBB analysis was updated to address a 1.7 percent mini-uprating program and plant life extension for the 60-year period of extended operation (Reference 4.8.31). In 2008, the 2003 primary loop piping LBB analysis conclusions were re-examined for the PBN extended power uprate (EPU) project. The results of 2008 EPU evaluation concluded the 2003 analysis remained applicable for the EPU project (Reference ML110750120).

The fatigue crack growth evaluation performed in WCAP-14439, Revision 2 is a defense in depth evaluation to demonstrate that small surface flaws do not become through-wall flaws over the life of the plant. The fatigue crack growth evaluation was based on a plant-specific model with representative design transients and cycles that are applicable to PBN.

Considering the LBB postulated crack stability analysis is related to the period of plant operation, the primary loop piping LBB analysis is a TLAA for SLR.

TLAA Evaluation

WCAP-14439-P/NP, Revision 4, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Point Beach Nuclear Plant Units 1 and 2 for the Subsequent License Renewal Program (80 Years)" (Reference 4.8.32) performed the LBB evaluation for an 80-year plant life. The analysis documented the plant-specific geometry, loading, and material properties used in the fracture mechanics evaluation.

The PBN Units 1 and 2 primary loop piping is constructed from forged stainless steel piping (A376-TP316) and cast austenitic stainless steel elbow fittings (A351-CF8M). The PBN Unit 2 steam generator (SG) inlet and outlet nozzles contain Alloy 82/182 dissimilar metal welds which are susceptible to primary water stress corrosion cracking (PWSCC). The welds have been repaired using Alloy 52/152 inlay to mitigate the PWSCC. Since the piping systems include cast austenitic stainless steel, fracture toughness considering thermal aging was determined for each heat of material. Fully aged fracture toughness properties were used for the LBB evaluation. The fully aged condition is applicable for plants operating beyond 15 EFPY for the CF8M materials (primary loop piping elbows for Units 1 and 2), which is the case for PBN.

The updates performed for WCAP-14439-NP included a recalculation of delta ferrite and fracture toughness properties based on NUREG/CR-4513, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems" (Reference 1.6.38). The chemistry data for the fracture mechanics parameters are obtained from the primary loop elbow fitting Certified Materials Test

Reports (CMTRs) Fracture toughness parameters were recalculated using information from NUREG/CR-4513.

The fatigue crack growth analysis used CLB cycles (40-year design cycles). As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound 80 years of plant operations. Therefore, the fatigue crack growth analysis for the LBB analysis has been projected to the end of the SPEO.

WCAP-14439-P/NP, Revision 4 provides the fracture mechanics demonstration of the reactor coolant system primary loop integrity consistent with the NRC position for exemption from consideration of dynamic effects noted in NUREG-0800 , Section 3.6.3 , "Leak-Before-Break Evaluation Procedures" (Reference 1.6.39). The analysis justifies the elimination of reactor coolant system primary loop pipe breaks from the structural design basis for the 80-year plant life as follows:

a. Stress corrosion cracking is precluded by use of fracture resistant materials in the primary loop piping and controls on reactor coolant chemistry, temperature, pressure, and flow during normal operation. Alloy 82/182 welds are present in the PBN Unit 2 steam generator (SG) inlet and outlet nozzle safe ends. The Alloy 82/182 welds are susceptible to PWSCC. To mitigate PWSCC due to the existence of Alloy 82/182, Alloy 52/152 weld inlay has been applied to the SG primary nozzle safe end welds that are exposed to primary coolant.
b. Water hammer should not occur in the reactor coolant system piping because of system design, testing, and operational considerations.
c. The effects of low and high cycle fatigue on the integrity of the primary piping are negligible.
d. Ample margin exists between the leak rate of small stable flaws and the capability of the PBN reactor coolant system pressure boundary leakage detection system.
e. Ample margin exists between the small stable flaw sizes of item (d) and larger stable flaws.
f. Ample margin exists in the fully-aged material properties to demonstrate stability of the critical flaws through the 80-year SPEO.
g. The critical postulated flaw locations are shown to be stable because of the ample margins described in d, e, and f above.

Based on the above, the LBB conditions and all recommended margins are satisfied for the reactor coolant system primary loop piping. Thus, the dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis for PBN Units 1 and 2 for the 80-year SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The analysis performed in WCAP-14439-P/NP, Revision 4 determined that the crack stability results, fracture toughness, and fatigue crack growth results are acceptable for 80 years of plant operation. Therefore, the LBB analysis is projected through the SPEO.

4.7.2. Leak-Before-Break of Reactor Coolant System Auxiliary Piping

TLAA Description

In 2001, Westinghouse performed plant specific leak-before-break (LBB) evaluations for the PBN Units 1 and 2 pressurizer surge line (Reference 4.8.33), residual heat removal (RHR) line (Reference 4.8.34), and accumulator line (Reference 4.8.35). In 2008, Westinghouse re-evaluated these LBB evaluations (Reference 4.8.36) as part of the PBN Units 1 and 2 Extended Power Uprate (EPU) license amendment request (Reference ML110750120). That evaluation was based on EPU loadings, operating pressure, and temperature parameters and concluded that the Reference 4.8.33 through 4.8.35 LBB evaluations, which are applicable for 60-year period of extended operation, remained valid for the EPU conditions.

Considering the LBB postulated crack stability analysis is related to the period of plant operation, these Class 1 auxiliary line LBB evaluations are TLAAs for SLR.

TLAA Evaluation

The aging effects that must be addressed for SLR include the potential for thermal aging of the auxiliary line piping components and fatigue crack growth. Thermal aging refers to the gradual change in the microstructure and properties of a material due to its exposure to elevated temperatures for an extended period of time. The only significant thermal aging effect on the auxiliary line piping components would be embrittlement of any duplex ferritic cast austenitic stainless steel components. As documented in the Reference 4.8.37 Westinghouse letter report, the PBN pressurizer surge lines, RHR lines and accumulator lines do not contain any duplex ferritic cast austenitic stainless steel materials. Therefore, thermal aging of these Class 1 auxiliary line piping components is not applicable for SLR. In addition, thermal aging of the stainless steel weld material was considered in the References 4.8.33 to 4.8.35 evaluations by assuming saturated conditions (fully aged).

Based on loading, piping geometry, and fracture toughness considerations, enveloping critical locations were determined for the Class 1 auxiliary lines at which LBB crack stability evaluations were made. Through-wall flaw sizes were postulated at the critical locations that would cause leakage at a rate ten times the leakage detection system capability. Including the requirement for margin of applied loads, large margins against flaw instability were demonstrated for the postulated flaw sizes. The References 4.8.33 to 4.8.35 auxiliary line LBB evaluations assumed the PBN 40-year design cycles for Class 1 components. As documented in Table 4.3.1-1, the 80-year projected cycles for SLR are significantly less than the original PBN 40-year design cycles. Therefore, the fatigue crack growth evaluations and results presented in References 4.8.33 to 4.8.35 remain valid for the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The LBB analyses associated with the pressurizer surge line, residual heat removal line, and accumulator line have been evaluated and determined to remain valid for the SPEO.

4.7.3. Flaw Tolerance Evaluation for Reactor Coolant Loop CASS Piping Components

TLAA Description

The PBN Units 1 and 2 reactor coolant loop piping elbows are constructed from cast austenitic stainless steel (CASS) material (ASTM A-351 Grade CF8M). CASS material is susceptible to thermal aging at the normal reactor operating temperature. Thermal aging of CASS material results in embrittlement, that is, a decrease in the ductility, impact strength, and fracture toughness of the material.

As part of the original license renewal application, PBN had chosen the evaluation method to disposition reduction in fracture toughness due to thermal embrittlement of the primary loop elbows. The evaluation credited was the primary loop leak-before-break (LBB) TLAA. During review of the application, the NRC staff issued RAI 3.1.1-1 requesting PBN clarify how the LBB TLAA manages the aging effect of reduction of fracture toughness due to thermal aging embrittlement for CASS primary loop elbows. The RAI was subsequently identified as confirmatory item (CI) 3.1.1-1. In the response to CI 3.1.1-1 (Reference ML051680493), PBN stated it would follow the recommendation of NUREG-1801 (Reference 1.6.40), AMP XI.M12, and that it would use enhanced volumetric examinations or a plant or component-specific flaw tolerance evaluation to demonstrate that CASS primary loop elbows have adequate fracture toughness. The staff found the PBN response acceptable and closed CI 3.1.1-1.

In July of 2005, Westinghouse developed flaw tolerance evaluation LTR-PAFM-05-58 (Reference 4.8.38) for the CASS reactor coolant loop (RCL) piping elbows in accordance with the requirements of ASME Code, Section XI. The evaluation considered the effect of thermal aging and included a fatigue crack growth evaluation based on plant-specific design transients and cycles that are applicable to PBN.

Considering the Reference 4.8.38 flaw tolerance evaluation is related to the period of plant operation; the flaw tolerance evaluation is a TLAA for SLR.

TLAA Evaluation

For SLR, the Reference 4.8.38 flaw tolerance evaluation has been updated for the 80-year SPEO (Reference 4.8.15). The evaluation includes plant-specific geometry, loading, material properties, and stresses used in the fracture mechanics evaluation. The susceptibility of CASS piping components to thermal aging is determined according to molybdenum content, casting methods, and delta ferrite content. In determining susceptibility of the CASS piping elbows to thermal aging, the delta ferrite content for PBN is estimated using Hull's Equivalent Factor in NUREG/CR-4513, Revisions 1 (Reference 1.6.41) and 2.

The evaluation procedures and acceptance criteria, contained in paragraph IWB-3640 of ASME Section XI Code, are used to determine the maximum allowable flaw size at the end of the inspection/evaluation period. A fatigue crack growth analysis is then performed considering the requirements for the thermal transients and the design or projected cycles for the 80-year service life. Thermal transients and the number of cycles applied during the design life of the plants are required in performing fatigue crack growth analysis. The fatigue crack growth analysis used the original 40-year CLB design cycles. As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound 80 years of plant operations. Note that the design cycles listed in Table 4.3.1-1 are conservatively used in the fatigue crack growth (FCG) analysis, except that for the evaluation of the longitudinal flaws, the 80-year allowable unit loading and unloading cycles of 3000 are used to provide a more appropriate cycle count based on historical plant data.

Since the reactor coolant water chemistry is monitored and maintained within very specific limits, contaminant concentrations are kept below the thresholds known to be conducive to stress corrosion cracking. The CASS piping elbows are therefore not susceptible to stress corrosion cracking and only fatigue crack growth needs to be considered.

The maximum acceptable initial flaw size for a given service life can then be determined such that the corresponding end of the inspection/evaluation period flaw size does not exceed the maximum allowable flaw size determined per Appendix C of ASME Section XI Code. Based on the guidance of ASME Section XI, evaluation LTR-PAFM-05-58-P/NP provides flaw tolerance charts that show the maximum acceptable flaw size for a range of flaw shapes at the susceptible CASS piping elbow locations in the hot leg, crossover leg and cold leg in each of the reactor coolant loops. Bounding evaluations applicable to both PBN Units 1 and 2 were performed for the susceptible elbow locations in each reactor coolant loop. The objective of the flaw tolerance evaluation is to demonstrate that even with thermal aging, the susceptible CASS components are flaw tolerant for 80 years of service.

The maximum acceptable flaw size for a range of flaw shapes for the susceptible CASS piping locations in the hot leg, crossover leg and cold leg are shown in Figure 6-1 through Figure 6-6 in Reference 4.8.15. These maximum acceptable initial flaw depths in all the three CASS components are deeper than the allowable flaw standards for the volumetric examination method in Table IWB-3514-2 in Section XI of the ASME Code 2007 Edition with 2008 Addendum (Reference 1.6.42). Therefore, even with thermal aging in the susceptible PBN reactor coolant loop CASS piping elbows, the susceptible piping locations have been shown to be tolerant of large flaws for 80-year plant life.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The evaluation performed in LTR-PAFM-05-58-P/NP, Revision 3 determined that the results of the flaw tolerance evaluation for susceptible reactor coolant loop CASS piping elbows are acceptable for 80 years of plant operation. Therefore, the flaw tolerance evaluation is projected through the SPEO.

4.7.4. Reactor Coolant Pump Flywheel Fatigue Crack Growth

TLAA Description

The reactor coolant pump (RCP) flywheel is discussed in PBN UFSAR Sections 4.2 and 15.4.3. During normal operation, the reactor coolant pump flywheel possesses sufficient kinetic energy to potentially produce high-energy missiles in the unlikely event of failure. Conditions that may result in overspeed of the reactor coolant pump increase both the potential for failure and the kinetic energy. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway.

An evaluation of the probability of failure over the 60-year period of extended operation was performed in WCAP-14535-A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination” (Reference ML18312A151), for all operating Westinghouse plants and certain Babcock and Wilcox plants. The evaluation demonstrates that the flywheel design has high structural reliability with a very high flaw tolerance and negligible flaw crack extension over a 60-year service life. The NRC reviewed and approved the evaluation (WCAP-14535-A) for application with certain conditions and limitations (Reference 4.8.39). PBN verified the RCP flywheel material and invoked this analysis as the basis for reducing the frequency of performing RCP flywheel inspections (Reference ML012700086).

WCAP-15666-A, Revision 1, “Extension of Reactor Coolant Pump Motor Flywheel Examination” (Reference ML18303A413), builds on the arguments in WCAP-14535-A and provides additional rationale, including a risk assessment of all credible flywheel speeds. WCAP-15666-A concludes that the change in risk is below Regulatory Guide 1.174 core damage frequency (CDF) and large early release frequency (LERF) acceptable guidelines. The NRC approved the use of this Topical Report in NRC SER, “Safety Evaluation of Topical Report WCAP-15666, Extension of Reactor Coolant Pump Motor Flywheel Examination” (Reference ML031250595). This analysis was used as a basis for a revision of PBN Technical Specification TS 5.5.6 which increased the flywheel inspection interval from 10 years to 20 years. The inspection is a qualified in-place ultrasonic (UT) examination over the volume from the inner bore of the RCP flywheel to the circle of one-half the outer radius or a surface examination (magnetic particle testing and/or liquid penetrant testing) of the exposed surfaces defined by the volume of the disassembled RCP flywheels.

Considering the RCP flywheel probability of failure is part of the CLB and is used to support safety determinations, and the probability of failure was based upon 60-year assumptions and 6,000 pump starts and stops, this fatigue analysis has been identified as a TLAA requiring evaluation for the SPEO.

TLAA Evaluation

RCP start and stop cycles for the 80-year SPEO have been projected using the same methodology utilized for the PBN 60-year PEO. The RCP start and stop cycles projected for the 60-year PEO were determined in the PBN response to RAI 4.4.2 (Reference ML050340169). Table 4.7.4-1 below replicates the Table developed in response to RAI 4.4.2 and includes an additional entry for the assumed RCP starts and stops during the 20-year SPEO. The projected number of

RCP starts and stops on an annual basis for the SPEO are assumed to be the same as the PEO.

Table 4.7.4-1
RCP Start/Stop Cycle Projections for 80 Years

Decade Number	Number of Years	Approximate Number of Start / Stop Cycles Per Year	Total Number of Start / Stop Cycles Per Period
1	10	5 (fill and vent)	50 (fill and vent)
2	10	5 (fill and vent) 10 (SG crevice flushing)	50 (fill and vent) 100 (SG crevice flushing)
3-6	40	5 (fill and vent)	200 (fill and vent)
7-8	20	5 (fill and vent)	100 (fill and vent)
Total	80	N/A	500

An evaluation of the probability of failure over the SPEO was performed by the PWROG. The evaluation is documented in PWROG-17011-NP-A, Revision 2, "Update for Subsequent License Renewal: WCAP-14535-A, 'Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,' and WCAP-15666-A, 'Extension of Reactor Coolant Pump Motor Flywheel Examination'" (Reference ML19318D189). PWROG-17011-NP-A confirms that the analyses performed under WCAP-14535-A and WCAP-15666-A justifying inspection of the RCP flywheel once every 20-years remains appropriate for application up to 80 years of operation.

The fatigue crack growth calculations assumed 6,000 cycles of RCP start and stop for the 80-year plant life which significantly bounds the projected 80-year RCP start and stop counts of 500 cycles. Therefore, the fatigue crack growth is negligible over an 80-year life of the RCP flywheel, even when assuming a large initial crack length.

The evaluation demonstrates that the RCP flywheel design has a high structural reliability with a very high flaw tolerance and negligible fatigue flaw crack extension over an 80-year service life.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The RCP flywheel fatigue crack growth analysis has been demonstrated to remain valid through the SPEO.

4.7.5. Reactor Coolant Pump Code Case N-481

TLAA Description

The PBN reactor coolant pumps (RCPs) are model 93A with SA-351, Grade CF-8 pump casings. ASME Code Case, N-481 "Alternate Examination Requirements for Cast Austenitic Pump Casings" (Reference 1.6.43), allowed the replacement of volumetric examinations of primary loop pump casing welds with fracture mechanics-based integrity evaluations supplemented by specific visual inspections. In March 2004, Code Case N-481 was annulled by ASME, and the information in

Code Case N-481 was implemented into the 2008 Addenda of ASME Code Section XI. Note that the ASME Section XI 2000 Addenda replaced the pump casing weld B-L-1 volumetric examinations with visual examinations, while the ASME Section XI 2008 Addenda eliminated the pump casing weld (B-L-1) examinations completely. The only required examination is a visual examination of the pump casing (B-L-2) when the pump is disassembled for maintenance or repair.

During the early 1990's when the Code Case N-481 was approved by the ASME, the Westinghouse Owners Group (WOG) performed a generic fracture mechanics analysis per Code Case N-481 for the various primary loop pump casing models found in Westinghouse-designed NSSS. The generic fracture mechanics analyses are documented in WCAP-13045 (Reference 4.8.40).

Loss of fracture toughness due to thermal aging embrittlement of CASS RCP casings is identified as an aging mechanism in NUREG-2191, AMP XI.M12. Specifically, GALL-SLR provides an allowance for continued use of flaw tolerance evaluations performed as part of implementation of Code Case N-481 to address thermal aging embrittlement and states that no further actions are needed if applicants demonstrate that the original flaw tolerance evaluation performed as part of Code Case N-481 implementation remains bounding and applicable for the SLR period or the evaluation is revised to be applicable for 80 years.

Considering this analysis is related to the period of plant operation, the analysis is a TLAA.

TLAA Evaluation

For SLR, an update to WCAP-13045 was completed in the Pressurized Water Reactor Owners Group (PWROG) report PWROG-17033-NP-A (Reference 4.8.41). The NRC approved PWROG-17033-P-A for SLR and provided conditions on the plant-specific applicability of the PWROG-17033-P-A and WCAP-13045 in terms of assessing the plant-specific loadings, material fracture toughness and transients (Reference ML20028D714).

Reconciliation report LTR-SDA-20-020-P/NP (Reference 4.8.42) was performed by Westinghouse for the PBN RCP casings to the generic fracture mechanics evaluation completed in PWROG-17033-P-A and WCAP-13045 to address the CASS thermal aging embrittlement concern for the SPEO. To address thermal aging embrittlement for the PBN casings with the use of PWROG-17033-P-A, the following four NRC-required conditions must be satisfied:

1. The licensee must confirm that its RCPs are Westinghouse-designed models.

The applicability of ASME Code Case N-481 to the PBN Units 1 and 2 RCP casings was demonstrated in WCAP-14705. Refer to Section 2 of LTR-SDA-20-020-NP for confirmation of the design of the PBN Units 1 and 2 RCPs.

2. The licensee must confirm that the Westinghouse-designed RCP is either a Model 63, Model 70, Model 93, Model 93A, Model 93A-1, Model 93D, Model 100A, or Model 100D, and fabricated with SA-351 CF8 or CF8M material.

Refer to Section 2 of LTR-SDA-20-020-NP for confirmation of the model and fabrication material of the PBN Units 1 and 2 RCPs.

3. For the crack stability analysis, the licensee must confirm that the screening loadings (force, moment, Japp and Tapp) used in WCAP-13045 bound the plant-specific loadings. The licensee must confirm the limiting material fracture toughness values (JIC, Tmat, and Jmax) used in WCAP-13045 and PWROG-17033-P-A, Revision 1, bound the plant-specific fracture toughness values. If the screening loadings and material fracture toughness values in the WCAP-13045 and PWROG-17033 reports bound plant-specific values, the licensee needs to discuss how the Technical Reports (TRs) are bounding in the subsequent license renewal application. If the screening loadings or material fracture toughness value in the WCAP-13045 and PWROG-17033-P-A reports do not bound plant-specific values, the licensee needs to submit a plant-specific crack stability analysis to demonstrate structural integrity of the RCP casing as part of the subsequent license renewal application.

Refer to Sections 3 and 4 of LTR-SDA-20-020-NP for the plant-specific compliance to these requirements.

4. For the fatigue crack growth (FCG) analysis, the licensee must confirm that the transient cycles specified in the WCAP-13045 or PWROG-17033 report bound the plant-specific transient cycles for the 80 years of operation. The licensee must confirm that the loadings used in the FCG analysis in WCAP-13045 bound the plant-specific applied loadings, considering potential increase in applied loading caused by plant-specific system operational changes, power uprate or piping modifications. If the FCG analysis inputs in WCAP-13045 bound the plant-specific conditions, the licensee must discuss how they are bounding in the subsequent license renewal application. If the FCG analysis inputs in WCAP-13045 do not bound the plant-specific conditions, the plant owner must provide a plant-specific analysis to demonstrate the FCG of the postulated flaw is within acceptable criteria as part of the subsequent license renewal application.

Refer to Section 5 of LTR-SDA-20-020-NP for the plant-specific compliance to these requirements.

The results presented in report LTR-SDA-20-020-NP justify the plant-specific applicability of PWROG-17033-NP- A and WCAP-13405 for the PBN RCP casings. The effect of thermal aging embrittlement has been evaluated and addressed in the report. Therefore, the PBN RCP casings are in compliance with ASME Code Case N-481 for the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The analysis associated with ASME Code Case N-481 has been demonstrated to remain valid through the SPEO.

4.7.6. Crane Load Cycle Limit

TLAA Description

A review of design specifications for cranes within the scope of SLR was performed to identify those cranes that were designed or otherwise required to meet the intent of Crane Manufacturers Association of America (CMAA) Specification 70-1975 (Reference 4.8.43) and, therefore, have a defined service life as measured in load cycles.

The defined service life for these cranes as measured in load cycles is identified as a TLAA for SLR.

TLAA Evaluation

Method of Evaluation-Scope

The cranes potentially subject to TLAA are those in compliance with NUREG-0612 (Reference ML070250180). As documented in UFSAR Appendix A.3, the following cranes comply with NUREG-0612 and are included in SLR scope:

- Containment polar cranes
- Auxiliary building crane
- Turbine building crane

Method of Evaluation - Acceptance Criteria

All PBN cranes were originally designed and constructed to meet the requirements of Specification 61 of the Electric Overhead Crane Institute (Reference 4.8.44). EOCI-61 did not require a specific fatigue analysis for cranes. NUREG-0612 requires that the design of heavy load overhead handling systems meet the intent of CMAA-70. As stated in Section 4.3.13 of NUREG-1839, CMAA Specification 70 and ANSI Standard B30.2-1976 (Reference 1.6.44) apply to the PBN containment polar cranes, auxiliary building cranes, and turbine building crane.

CMAA Specification 70 presents the bounding combinations of the number of load cycles and mean effective load factors for each service class. These define the acceptable service limits for the TLAA. The following paragraph describes the method of selecting the service class from CMAA Specification 70 that corresponds to the service class originally specified from EOCI Specification 61 This service class is used with CMAA Specification 70, Table 2.8-1 to identify the applicable number of load cycles for that specific service class.

Appendix A of EOCI Specification 61 defines Class A as:

“Standby service: For such use as powerhouse, pump rooms, motor rooms, transformer repair, etc. where the crane is used very infrequently. These cranes must be substantially designed to handle expensive loads.”

The corresponding service class stated in Section 70-2 of CMAA Specification 70 is Class A service, which is defined as the following:

"Standby or Infrequent service: This service class covers cranes which may be used in installations such as powerhouses, public utilities, turbine rooms, motor rooms and transformer stations where precise handling of equipment at slow speeds with long, idle periods between lifts required. Capacity loads may be handled for initial installation of equipment and for infrequent maintenance."

Based on the comparison of service classes described in the original design specification (EOCI Specification 61) to CMAA Specification 70, the applicable service class for the PBN containment polar cranes, auxiliary building cranes, and turbine building crane is Class A.

Table 2.8-1 of CMAA Specification 70 states that a range of load cycles from 20,000 to 100,000 was considered for cranes in Service Class A service thus establishing the envelope for the acceptable number of load cycles for this TLAA. The total projected load cycles for the PBN containment polar cranes, auxiliary building cranes, and turbine building crane based on past and future use are summarized in Table 4.7.6-1.

Table 4.7.6-1
Evaluation Summary of Crane Operation

Crane	CMAA Service Class	Maximum Number of Load Cycles	Projected Number of Load Cycles for 80 years	Valid for 80 years
Containment Polar Cranes	Class A	100,000	96,000	Yes
Auxiliary Building Crane	Class A	100,000	8,384	Yes
Turbine Building Crane	Class A	100,000	Note 1	Yes

Note 1: as stated in Section 4.3.13 of NUREG-1839, the primary auxiliary building (PAB) crane is the most limiting for rated load lifts, while the containment crane is most limiting for partial load lifts. Therefore, both bound the load lifts for the turbine building crane.

Containment Polar Crane Evaluation

Section 4.3.13 of NUREG-1839 provides the basis for the number of lifts the containment polar cranes would be subjected to during the 60-year period of extended operation (PEO). This total number of lifts assumed 60 outages, with 20 days of lifting per outage, and a total of 40 lifts per day. This equates to a total number of 48,000 lifts. Conservatively doubling this lift total for the 80-year SPEO equals 96,000 lifts which is less than the 100,000 lift limit for Service Class A in CMAA Specification-70; therefore, the TLAA for the containment polar crane remains valid.

Auxiliary Building Crane Evaluation

Section 4.3.13 of NUREG-1839 provides the basis for the number of lifts the auxiliary building crane would be subjected to during the 60-year period of extended operation (PEO). This total number of lifts assumed 2700 fuel cask lifts (NUHOMS), 600 maintenance load lifts, and 892 original fuel cask lifts (VSC-24). This equates to a total number of 4,192 lifts. Conservatively doubling this lift total for the 80-year SPEO equals 8,384 which is significantly less than the 100,000 lift limit for Service Class A in CMAA Specification-70; therefore, the TLAA for the containment polar crane remains valid.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The containment polar cranes, auxiliary building crane, and turbine building crane load cycle evaluation has been demonstrated to remain valid through the SPEO.

4.8. REFERENCES

4.8.1 Westinghouse WCAP-18555-NP, Revision 1, "Point Beach Units 1 and 2 Time-Limited Aging Analyses on Reactor Vessel Integrity for Subsequent License Renewal," August 2020 (Enclosure 4, Attachment 3).

4.8.2 Westinghouse Report WCAP-18124-NP-A, Revision 0, "Fluence Determination with RAPTOR-M3G and FERRET," July 2018.

4.8.3 Framatome Topical Report BAW-2166, "B&W Owners Group Response to Generic Letter 92-01," ADAMS Accession (Legacy) Number 9207060227.

4.8.4 Framatome Topical Report BAW-2222, Revision 1, "Reactor Vessel Working Group Response to Closure Letters to NRC Generic Letter 92-01," ADAMS Accession (Legacy) Number 9407060101 and 9407010286.

4.8.5 Framatome Topical Report BAW-2192PA, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Level A & B Service Loads," ADAMS Accession (Legacy) 9406240261 (P), 9312220294 (NP).

4.8.6 Framatome Topical Report BAW-2178PA, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Level C & D Service Loads," ADAMS Accession (Legacy) 9406290288 (P).

4.8.7 Framatome Topical Report BAW-2467NP, Revision 1, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessel of Point Beach Units 1 and 2 for Extended Life through 53 Effective Full Power Years," ADAMS Accession Number ML042660313.

4.8.8 Framatome Topical Report BAW-2192, Revision 0, Supplement 3P/3NP, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels A & B Service Loads," October 2020 (Enclosure 4, Attachment 4 and Enclosure 5, Attachment 3).

4.8.9 Framatome Topical Report BAW-2178, Revision 0, Supplement 2P/2NP, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels C & D Service Loads," October 2020 (Enclosure 4, Attachment 5 and Enclosure 5, Attachment 4).

4.8.10 Regulatory Guide 1.161, Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 ft-lbs, June 1995.

4.8.11 Framatome Technical Report ANP-3886P/NP, Revision 0, PWROG-20043-P/NP, "PWROG – PBN Unit 1 IS Plate A9811-1 Equivalent Margins Analysis for SLR," October 2020 (Enclosure 4, Attachment 6 and Enclosure 5, Attachment 5).

4.8.12 EPRI Technical Report, "Materials Reliability Program: Upper-Shelf Fracture Toughness of Irradiated Reactor Pressure Vessel Steel (MRP-439)," 2019.

4.8.13 Structural Integrity Associates, Inc. Report No. 2000088.401, Revision 2, “Cycle Counts and Fatigue Projections for 80 Years of Plant Operation for Point Beach Nuclear Units 1 and 2,” October 19, 2020 (Enclosure 4, Attachment 7).

4.8.14 WCAP-7907-PA, LOFTRAN Code Description, April 1984.

4.8.15 Westinghouse LTR-PAFM-05-58-P/NP, Revision 3, “Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Piping Components in Point Beach Units 1 and 2 for 80 years,” July 2020 (Enclosure 4, Attachment 18 and Enclosure 5, Attachment 12).

4.8.16 EPRI Report TR-104534, Volume 1, 2 & 3, “Fatigue Management Handbook,” Research Project 3321,” Revision 1, December 1994.

4.8.17 EPRI Report 1024995, “Environmentally-Assisted Fatigue Screening: Process and Technical Basis for Identifying EAF Limiting Locations,” 2012.

4.8.18 Westinghouse LTR-SDA-II-20-05-P/NP, Revision 2, “Environmentally Assisted Fatigue Screening Results for Point Beach Unit 1 and Unit 2 Safety Class 1 Primary Equipment,” June 30, 2020 (Enclosure 4, Attachment 8 and Enclosure 5, Attachment 6).

4.8.19 Structural Integrity Associates, Inc. Report No. 2000088.402, Revision 1, “Environmentally-Assisted Fatigue Evaluation for 80 Years of Plant Operation for Point Beach Nuclear Units 1 and 2,” September 25, 2020 (Enclosure 4, Attachment 9).

4.8.20 Westinghouse LTR-SDA-II-20-08-P/NP, Revision 1, “Environmentally Assisted Fatigue Evaluation Results for the Point Beach Unit 1 and Unit 2 Primary Equipment Sentinel Locations for Subsequent License Renewal,” July 15, 2020 (Enclosure 4, Attachment 10 and Enclosure 5, Attachment 7).

4.8.21 Westinghouse LTR-SDA-II-20-13-P/NP, Revision 2, “Environmentally Assisted Fatigue Evaluation Results for the Point Beach Unit 1 and Unit 2 Pressurizer Lower Head for Subsequent License Renewal,” September 23, 2020 (Enclosure 4, Attachment 11 and Enclosure 5, Attachment 8).

4.8.22 Structural Integrity Associates, Inc. File No. 2000088.310P-REDACTED/PROPRIETARY, Revision 1, “EAF Refined Analyses (Charging Nozzle, Hot Leg Surge Nozzle, SI Nozzle, SI/RHR Tee),” August 14, 2020 (Enclosure 4, Attachment 12 and Enclosure 5, Attachment 9).

4.8.23 Structural Integrity Associates, Inc. Calculation No. PBCH-03Q-301, Revision 3, “Evaluation of Thermal Stratification Due to Valve Leakage,” September 25, 2020 (Enclosure 4, Attachment 13).

4.8.24 ASME Code Case N-809, “Reference Fatigue Crack Growth Rate Curves for Austenitic Stainless Steels in Pressurized Water Reactor Environments, Section XI, Division 1,” ASME International, dated June 23, 2015.

4.8.25 American Petroleum Institute, API-579-1/ASME FFS-1, “Fitness-For-Service,” June 2016.

4.8.26 Westinghouse LTR-SDA-20-064-P/NP, Revision 1, “ASME Section XI Appendix L Evaluation Results for the Point Beach Units 1 and 2 Pressurizer Spray Nozzles,” October 7, 2020 (Enclosure 4, Attachment 14 and Enclosure 5, Attachment 10).

4.8.27 DOR Guidelines, “Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors,” U. S. Nuclear Regulatory Commission, June 1979.

4.8.28 EPRI NP-1558, “A Review of Equipment Aging Theory and Technology,” Electric Power Research Institute, September 1980.

4.8.29 Structural Integrity Associates Calculation PBCH-06Q-301, Revision 1, “Containment Penetration Fatigue Evaluation,” November 11, 2003 (Enclosure 4, Attachment 15).

4.8.30 WCAP-14439, ”Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Point Beach Units 1 and 2 Nuclear Power Plants,’’ December 1996.

4.8.31 WCAP-14439-P, Revision 2, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Point Beach Nuclear Plant Units 1 and 2 for the Power Uprate And License Renewal Program,” September 2003.

4.8.32 Westinghouse WCAP-14439-P/NP, Revision 4, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Point Beach Nuclear Plant Units 1 and 2 for the Subsequent License Renewal Program (80 Years),” June 2020 (Enclosure 4, Attachment 16 and Enclosure 5, Attachment 11).

4.8.33 WCAP-15065-P-A, Revision 1, “Technical Justification for Eliminating Pressurizer Surge Line Rupture as the Structural Design Basis for Point Beach Units 1 and 2 Nuclear Plants,” June 2001.

4.8.34 WCAP-15105-P-A, Revision 1, “Technical Justification for Eliminating Residual Heat Removal (RHR) Rupture as the Structural Design Basis for Point Beach Units 1 and 2 Nuclear Plants,” June 2001.

4.8.35 WCAP-15107-P-A, Revision 1, “Technical Justification for Eliminating Accumulator Rupture as the Structural Design Basis for Point Beach Units 1 and 2 Nuclear Plants,” June 2001.

4.8.36 CN-PAFM-08-54 Revision 0, "Point Beach Units 1 and 2 Extended Power Uprate (EPU) Leak-Before-Break (LBB) Evaluation for Reactor Coolant Loop, Accumulator, RHR, and Surge Line," September 25, 2008.

4.8.37 Westinghouse LTR-SDA-II-20-06, Revision 1, "Leak-Before-Break Reconciliation of the Point Beach Units 1 and 2 Pressurizer Surge Line, Residual Heat Removal Line, and Accumulator Line Piping Systems for the Subsequent License Renewal Program," May 4, 2020 (Enclosure 4, Attachment 17).

4.8.38 Westinghouse Evaluation LTR-PAFM-05-58, Revision 0, "Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Piping Components in Point Beach Units 1 and 2 for 80 years," July 2005.

4.8.39 NRC Letter, "Acceptance for Referencing of Topical Report WCAP-14535-A, Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination," dated September 12, 1996.

4.8.40 Westinghouse Report WCAP-13045, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems," September 1991.

4.8.41 Westinghouse Report PWROG-17033-NP-A, Revision 1, "Update for Subsequent License Renewal: WCAP-13045, Compliance to ASME Code Case N-481 of Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Steams," November 2019.

4.8.42 LTR-SDA-20-020-P/NP, Revision 1, "Point Beach Units 1 and 2 Reactor Coolant Pump Casings ASME Code Case N-481 Analysis for 80-year Subsequent License Renewal (SLR)," July 2020 (Enclosure 4, Attachment 19 and Enclosure 5, Attachment 13).

4.8.43 Crane Manufacturers Association of America Specification 70, 1975.

4.8.44 Electric Overhead Crane Institute (EOCI) Specification 61 for Electric Overhead Traveling Cranes.

APPENDIX A

UPDATED FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

POINT BEACH NUCLEAR PLANT UNITS 1 AND 2

SUBSEQUENT LICENSE RENEWAL APPLICATION

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16.0 AGING MANAGEMENT PROGRAMS AND TIME-LIMITED AGING ANALYSIS ACTIVITIES

16.1. Introduction

The application for a renewed operating license is required by 10 CFR 54.21(d) to include a Final Safety Analysis Report (FSAR) supplement. This chapter comprises the Updated Final Safety Analysis Report (UFSAR) supplement of the PBN Subsequent License Renewal Application (SLRA) and includes the following sections:

- Section 16.1.1 contains a listing of the PBN aging management programs (AMPs) for subsequent license renewal (SLR) in the order of NUREG-2191 programs, that is NUREG-2191 Chapter X and NUREG-2191 Chapter XI, including the status of the programs at the time the SLRA was submitted. There are no site-specific AMPs for PBN.
- Section 16.1.2 contains a listing of the time-limited aging analyses (TLAAs).
- Section 16.1.3 contains a discussion stating the relationship between the NextEra Energy (NEE) Quality Assurance (QA) Program at PBN and the AMPs' corrective actions, confirmation process, and administrative controls elements.
- Section 16.1.4 contains a summary of the PBN Operating Experience (OE) Program.
- Section 16.2 contains a summary of the PBN programs used for managing the effects of aging. These AMPs are associated with either NUREG-2191 Chapter X or Chapter XI.
- Section 16.3 contains a summary of the TLAAs applicable to the subsequent period of extended operation (SPEO).
- Section 16.4 contains the PBN SLR Commitment List and the AMPs' planned implementation schedule.

The integrated plant assessment for SLR identified new and existing AMPs necessary to provide reasonable assurance that systems, structures, and components (SSCs) within the scope of SLR will continue to perform their intended functions consistent with the Current Licensing Basis (CLB) for the SPEO. The SPEO is defined as 20 years from the current renewed operating license expiration date.

16.1.1. Aging Management Programs

AMPs for PBN SLR are listed in Table 16-1 and described in Section 16.2. The AMPs are listed chronologically as they appear in NUREG-2191, with the Chapter X AMPs first, followed by the Chapter XI AMPs. The PBN AMPs are categorized as either existing AMPs or new AMPs for SLR. The existing PBN AMPs are renamed and enhanced as necessary to more closely align with AMPs described in NUREG-2191.

Table 16-1 reflects the status of the PBN AMPs at the time of the SLRA submittal. Regulatory commitments, which include AMP enhancements and implementation schedules for PBN AMPs are identified in the PBN SLR Commitment List within Section 16.4.

Table 16-1
List of PBN Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
X.M1	Fatigue Monitoring (Section 16.2.1.1)	Existing
X.M2	Neutron Fluence Monitoring (Section 16.2.1.2)	Existing
X.S1	Concrete Containment Unbonded Tendon Prestress (Section 16.2.1.3)	Existing
X.E1	Environmental Qualification of Electric Equipment (Section 16.2.1.4)	Existing
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section 16.2.2.1)	Existing
XI.M2	Water Chemistry (Section 16.2.2.2)	Existing
XI.M3	Reactor Head Closure Stud Bolting (Section 16.2.2.3)	Existing
XI.M4	BWR Vessel ID Attachment Welds Not Applicable (PBN U1 and U2 are PWRs)	N/A
XI.M5	Not Applicable (Deleted from NUREG-2191)	N/A
XI.M6	Not Applicable (Deleted from NUREG-2191)	N/A
XI.M7	BWR Stress Corrosion Cracking Not Applicable (PBN U1 and U2 are PWRs)	N/A
XI.M8	BWR Penetrations Not Applicable (PBN U1 and U2 are PWRs)	N/A
XI.M9	BWR Vessel Internals Not Applicable (PBN U1 and U2 are PWRs)	N/A
XI.M10	Boric Acid Corrosion (Section 16.2.2.4)	Existing
XI.M11B	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (Section 16.2.2.5)	Existing
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (Section 16.2.2.6)	New
XI.M16A	Reactor Vessel Internals (Section 16.2.2.7)	Existing
XI.M17	Flow-Accelerated Corrosion (Section 16.2.2.8)	Existing
XI.M18	Bolting Integrity (Section 16.2.2.9)	Existing
XI.M19	Steam Generators (Section 16.2.2.10)	Existing
XI.M20	Open-Cycle Cooling Water System (Section 16.2.2.11)	Existing
XI.M21A	Closed Treated Water Systems (Section 16.2.2.12)	Existing
XI.M22	Boraflex Monitoring Not Applicable (PBN U1 and U2 do not credit Boraflex as a neutron absorber in spent fuel pit criticality analyses.)	N/A
XI.M23	Inspection of Overhead Heavy Load Handling Systems (Section 16.2.2.13)	Existing
XI.M24	Compressed Air Monitoring (Section 16.2.2.14)	Existing

Table 16-1 (continued)
List of PBN Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
XI.M25	BWR Reactor Water Cleanup System Not Applicable (PBN U1 and U2 are PWRs)	N/A
XI.M26	Fire Protection (Section 16.2.2.15)	Existing
XI.M27	Fire Water System (Section 16.2.2.16)	Existing
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks (Section 16.2.2.17)	Existing
XI.M30	Fuel Oil Chemistry (Section 16.2.2.18)	Existing
XI.M31	Reactor Vessel Material Surveillance (Section 16.2.2.19)	Existing
XI.M32	One-Time Inspection (Section 16.2.2.20)	Existing
XI.M33	Selective Leaching (Section 16.2.2.21)	New
XI.M35	ASME Code Class 1 Small-Bore Piping (Section 16.2.2.22)	Existing
XI.M36	External Surfaces Monitoring of Mechanical Components (Section 16.2.2.23)	Existing
XI.M37	Flux Thimble Tube Inspection (Section 16.2.2.24)	Existing
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section 16.2.2.25)	New
XI.M39	Lubricating Oil Analysis (Section 16.2.2.26)	Existing
XI.M40	Monitoring of Neutron-Absorbing Materials other than Boraflex Not Applicable (PBN U1 and U2 do not credit neutron absorbers in the spent fuel pit criticality analyses.)	N/A
XI.M41	Buried and Underground Piping and Tanks (Section 16.2.2.27)	Existing
XI.M42	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section 16.2.2.28)	New
XI.S1	ASME Section XI, Subsection IWE (Section 16.2.2.29)	Existing
XI.S2	ASME Section XI, Subsection IWL (Section 16.2.2.30)	Existing
XI.S3	ASME Section XI, Subsection IWF (Section 16.2.2.31)	Existing
XI.S4	10 CFR Part 50, Appendix J (Section 16.2.2.32)	Existing
XI.S5	Masonry Walls (Section 16.2.2.33)	Existing
XI.S6	Structures Monitoring (Section 16.2.2.34)	Existing
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section 16.2.2.35)	Existing
XI.S8	Protective Coating Monitoring and Maintenance (Section 16.2.2.36)	Existing
XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 16.2.2.37)	Existing

Table 16-1 (continued)
List of PBN Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
XI.E2	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits (Section 16.2.2.38)	Existing
XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 16.2.2.39)	Existing
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 16.2.2.40)	New
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 16.2.2.41)	New
XI.E4	Metal Enclosed Bus (Section 16.2.2.42)	New
XI.E5	Fuse Holders Not Applicable (PBN U1 and U2 do not have any components within this program scope.)	N/A
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 16.2.2.43)	New
XI.E7	High-Voltage Insulators (Section 16.2.2.44)	New
N/A – PBN Site-Specific Program	Not Applicable (PBN U1 and U2 do not have any unique site-specific AMPs beyond those described in NUREG-2191)	N/A

16.1.2. <u>Time-Limited Aging Analyses</u>

The TLAA summaries applicable to PBN during the SPEO are identified in the table below and described in the sections subordinate to Section 16.3:

Table 16-2
List of Time-Limited Aging Analyses

Category (Section)	Time-Limited Aging Analyses Name	Section
Reactor Vessel Neutron Embrittlement (16.3.2)	Neutron Fluence Projections	16.3.2.1
	Pressurized Thermal Shock	16.3.2.2
	Upper-Shelf Energy	16.3.2.3
	Adjusted Reference Temperature	16.3.2.4
	Pressure-Temperature Limits and Low Temperature Overpressure Protection (LTOP) Setpoints	16.3.2.5
Metal Fatigue (16.3.3)	Metal Fatigue of ASME Class 1 Components	16.3.3.1
	ASME Code, Section III, Class 1 Component Fatigue Waivers	16.3.3.2
	Metal Fatigue of Non-Class 1 Components	16.3.3.3
	Environmentally-Assisted Fatigue	16.3.3.4
Environmental Qualification of Electric Equipment (16.3.4)	Environmental Qualification of Electric Equipment	16.3.4
Concrete Containment Tendon Prestress (16.3.5)	Concrete Containment Tendon Prestress	16.3.5
Containment Liner Plate, Metal Containments, and Penetrations Fatigue (16.3.6)	Containment Liner Plate, Metal Containments, and Penetrations Fatigue	16.3.6
Other Site-Specific TLAAs (16.3.7)	Leak-Before-Break of Reactor Coolant System Loop Piping	16.3.7.1
	Leak-Before-Break of Reactor Coolant System Auxiliary Piping	16.3.7.2
	Flaw Tolerance Evaluation for Reactor Coolant Loop CASS Piping Components	16.3.7.3
	Reactor Coolant Pump Flywheel Fatigue Crack Growth	16.3.7.4
	Reactor Coolant Pump Code Case N-481	16.3.7.5
	Crane Load Cycle Limits	16.3.7.6

16.1.3. Quality Assurance Program and Administrative Controls

The NEE Quality Assurance (QA) Program for PBN implements the requirements of 10 CFR 50, Appendix B (Reference 1.6.45), and is consistent with the summary in Appendix A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1),” of NUREG-2192. The NEE QA Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related SSCs and commodity groups that are included within the scope of the AMPs. Generically, the three elements are applicable as follows.

The corrective action, confirmation process, and administrative controls of the NEE QA Program are applicable to all AMPs and activities during the SPEO. The NEE QA Program procedures, review and approval processes, and administrative controls are implemented, as described in the NEE Topical QA Report, in accordance with the requirements of 10 CFR 50, Appendix B. The NEE QA Program applies to all structures and components (SCs) that have aging effects managed by a PBN AMP. Corrective actions and administrative (document) control for both safety-related and nonsafety-related SCs are accomplished in accordance with the established PBN corrective action program and document control program and are applicable to all AMPs and activities during the SPEO. The confirmation process is part of the corrective action program and includes reviews to assure adequacy of corrective actions, tracking and reporting of open corrective actions, and review of corrective action effectiveness. Any follow-up inspections required by the confirmation process are documented in accordance with the corrective action program.

16.1.4. Operating Experience Program

The PBN OE Program captures the OE from site-specific and industry sources and is systematically reviewed on an ongoing basis in accordance with the NEE QA Program. This OE program also meets the provisions of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff."

The PBN OE Program interfaces with and relies on active participation in the Institute of Nuclear Power Operations (INPO) OE program, as endorsed by the U.S. Nuclear Regulatory Commission (NRC). In accordance with these programs, all incoming OE items are screened to determine whether they may involve age-related degradation or aging management impacts. Research and development are also reviewed. Items so identified are further evaluated, and the AMPs are either enhanced, or new AMPs are developed, as appropriate, when it is determined through these evaluations that the effects of aging may not be adequately managed. Training on age-related degradation and aging management is provided to those personnel responsible for implementing the AMPs and to those who may submit, screen, assign, evaluate, or otherwise process site-specific and industry OE. Site-specific OE associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the PBN OE Program.

16.2. Aging Management Programs

16.2.1. NUREG-2191 Chapter X Aging Management Programs

This section provides UFSAR summaries of the SLR AMPs associated with TLAAs.

16.2.1.1. Fatigue Monitoring

The PBN Fatigue Monitoring AMP is an existing AMP that provides an acceptable basis for managing fatigue of components that are subject to fatigue or other types of cyclical loading to ensure the TLAAs remain valid in accordance with 10 CFR 54.21(c)(1)(iii). The aging management program monitors and tracks the number of occurrences and severity of design basis transients assessed in the applicable fatigue or cyclical loading analyses, including those in applicable CUF analyses, environmental-assisted fatigue analyses (CUF_{en} analyses), maximum allowable stress range reduction/expansion stress analyses for ANSI B31.1 and ASME Code Class 2 and 3 components, ASME III fatigue waiver analyses, and cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses.

The program manages cumulative fatigue damage or cracking induced by fatigue or cyclic loading in the applicable structures and components through performance of activities that monitor one or more relevant analysis parameters, such as CUF values, CUF_{en} values, design transient cycle limit values, or predicted flaw size values. The program also sets applicable acceptance criteria (limits) on these parameters. The program verifies the continued acceptability of existing analyses through cycle counting or parameter monitoring to demonstrate that they continue to meet the appropriate limits.

The program also implements appropriate corrective actions (e.g., reanalysis, component or structure inspections, or component or structure repair or replacement activities) when acceptance limits are approached.

This AMP also relies on the PBN Water Chemistry AMP to provide monitoring of appropriate environmental parameters for calculating environmental fatigue multipliers (F_{en} values).

16.2.1.2. Neutron Fluence Monitoring

The PBN Neutron Fluence Monitoring AMP, previously the fluence and uncertainty calculation portion of the PBN Reactor Vessel Integrity Program, is an existing AMP. This program monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to reactor pressure vessel and reactor internal components to ensure that applicable reactor pressure vessel neutron irradiation embrittlement analyses (i.e., TLAAs) and radiation-induced aging effect assessment for reactor internal components will remain within their applicable limits.

This program has two aspects, one to verify the continued acceptability of existing analyses through neutron fluence monitoring, and the other to provide periodically updated evaluations of the analyses involving neutron fluence inputs to demonstrate that they continue to meet the appropriate limits defined in the CLB.

Monitoring is performed to verify the adequacy of neutron fluence projections, which are defined for the CLB in NRC approved reports. For fluence monitoring activities that apply to the beltline region of the reactor pressure vessel(s), the calculational methods are generally performed in a manner that is consistent with RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," March 2001. Additional justifications may be necessary for neutron fluence monitoring, regarding methods that are applied to reactor pressure vessel locations outside of the beltline region of the vessels or to reactor internal components.

This program's results are compared to the neutron fluence parameter inputs used in the neutron embrittlement analyses for reactor pressure vessel components. This includes but is not limited to the neutron fluence inputs for the reactor pressure vessel upper shelf energy analyses, pressure-temperature limits analyses, and low temperature overpressure protection (LTOP) that are required to be performed in accordance in 10 CFR Part 50, Appendix G requirements, and for PWRs, those safety analyses that are performed to demonstrate adequate protection of the reactor pressure vessels against the consequences of pressurized thermal shock (PTS) events, as required by 10 CFR 50.61 and applicable to the CLB. Comparisons to the neutron fluence inputs for other analyses may include those for mean RT_{NDT} and aging effect assessments for PWR reactor internals that are induced by neutron irradiation exposure mechanisms.

Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H requirements and through implementation of the Reactor Vessel Material Surveillance Program may provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in the plant technical specifications or in specific regulations of 10 CFR Part 50 may apply, including those in 10 CFR Part 50, Appendix G; 10 CFR 50.55a; and the PTS requirements in 10 CFR 50.61.

16.2.1.3. Concrete Containment Unbonded Tendon Prestress

The PBN Concrete Containment Unbonded Tendon Prestress AMP is an existing AMP for SLR that monitors and assesses the continued adequacy of prestressing force for each tendon group (dome, hoop and vertical) of the unbonded tendons for the pre-stressed concrete containments through the SPEO. Loss of containment tendon prestressing forces is a TLAA that has been projected to the end of the SPEO. For completeness, the PBN Concrete Containment Unbonded Tendon Prestress AMP serves to confirm continued validity of the prestress force projections through the end of the SPEO, a 10 CFR 54.21(c)(1)(iii) disposition.

Measurement and assessment of tendon prestress forces, in comparison to lower bound and (minimum) required force, comprise the AMP. Tendon prestress forces are periodically measured during "physical" inspections, concurrent with other required inspections by the PBN ASME Section XI, Subsection IWL AMP. The PBN Concrete Containment Unbonded Tendon Prestress AMP monitors the loss of containment tendon prestressing forces throughout the life of the plant for each tendon group (i.e., dome, hoop and vertical) to ensure, during each inspection, the trend lines of the measured prestressing forces remain above the (minimum) required force before the next scheduled inspection. Otherwise, corrective actions are taken to ensure containment prestress adequacy. Upper and lower bounds and regression trends are assessed based on the guidance of Nuclear Regulatory Commission (NRC) Information Notice (IN) 99-10, “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments” and Regulatory Guide (RG) 1.35.1, “Determining Prestressing Forces for Inspection of Prestressed Concrete Containments” for calculating prestressing losses and predicted forces.

The PBN Concrete Containment Unbonded Tendon Prestress AMP is part of the Pre-Stressed Concrete Containment Tendon Surveillance Program described in Technical Requirements Manual (TRM) 4.17 and Technical Specification (TS) 5.5.17. The program incorporates plant-specific and industry OE.

16.2.1.4. Environmental Qualification of Electric Equipment

The PBN Environmental Qualification (EQ) of Electric Equipment AMP, previously the PBN EQ Program, is an existing AMP that implements the EQ requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49, and manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. This AMP provides the requirements for the EQ of electrical equipment important to safety that could be exposed to harsh environment accident conditions as required by 10 CFR 50.49 and RG 1.89, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants." This AMP is established per the requirements of 10 CFR 50.49 to demonstrate that certain electrical components located in harsh plant environments (i.e., 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 a main steam line break (MSLB) inside or outside the containment, from elevated temperatures or high radiation or steam, or their combination) are qualified to perform their safety function in those harsh environments after the effects of inservice (operational) aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ, and that the equipment be demonstrated to function in the harsh environment, following aging.

Equipment covered by this AMP has been evaluated to determine if the existing EQ aging analyses can be projected to the end of the SPEO by reanalysis. When analysis cannot justify a qualified life in excess of the SLR period, then the component parts are replaced, refurbished, or requalified prior to exceeding the qualified life as required by 10 CFR 50.49. Aging evaluations for EQ equipment that specify a qualification of at least 60 years are TLAAs for SLR. The PBN EQ of Electrical Equipment AMP is implemented in accordance with 10 CFR 50.49 and 10 CFR 54.21(c)(1)(iii).

16.2.2. NUREG-2191 Chapter XI Aging Management Programs

This section provides UFSAR summaries of the NUREG-2191 Chapter XI AMPs credited for managing the effects of aging.

16.2.2.1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The PBN ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP is an existing AMP that identifies and corrects degradation in ASME Code Class 1, 2, and 3 pressure-retaining components and piping. The AMP manages the aging effects of loss of material, cracking and loss of mechanical closure. The program consists of periodic volumetric, surface, and/or visual examination of ASME Code Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting for assessment, signs of degradation, and corrective actions. This program will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC in accordance with 10 CFR 50.55a prior to implementation.

In-service inspections of the PBN Units 1 and 2 ASME Code, Section XI, Appendix L pressurizer spray nozzle safe end piping will be performed once in each 10-year ISI interval with the first inspection being performed no earlier than 10 years prior to the SPEO and no later than the last refueling outage prior to the SPEO.

All examinations and inspections performed in accordance with the program plan are documented by records and reports, which are submitted to the NRC as required by IWA-6000.

16.2.2.2. Water Chemistry

The PBN Water Chemistry AMP, previously known as the Water Chemistry Control Program, is an existing AMP that mitigates the aging effects of loss of material due to corrosion, cracking due to stress corrosion cracking (SCC) and related mechanisms, and reduction of heat transfer due to fouling in components exposed to treated water. The PBN Water Chemistry AMP controls treated water for impurities (e.g., chloride, fluoride, and sulfate) that accelerate corrosion, and is generally effective in removing impurities from intermediate and high flow areas. This AMP includes periodic monitoring and control of the treated water in order to minimize loss of material or cracking based on the industry guidelines contained in Electric Power Research Institute (EPRI) 3002000505, “PWR Primary Water Chemistry Guidelines,” Revision 7, and EPRI 3002010645, “PWR Secondary Water Chemistry Guidelines,” Revision 8. The PBN Water Chemistry AMP is augmented by the PBN One-Time Inspection AMP, to verify the AMP effectiveness in managing corrosion-susceptible components (i.e., components located in areas exposed to low or stagnant flow).

16.2.2.3. Reactor Head Closure Stud Bolting

The PBN Reactor Head Closure Stud Bolting AMP is an existing AMP related to and currently part of the ASME Section XI, Subsections IWB, IWC and IWD, portion of the PBN ISI Program. This AMP includes (a) ISI in conformance with the requirements of the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, and (b) preventive measures to mitigate cracking. The program also relies on recommendations to address reactor head stud bolting degradation as delineated in NRC RG 1.65, Revision 1.

16.2.2.4. Boric Acid Corrosion

The PBN Boric Acid Corrosion AMP is an existing AMP that manages the aging effects of loss of material, increased resistance of connection, and mechanical closure integrity due to aggressive chemical attack resulting from borated water leaks. This AMP utilizes systematic inspections, leakage evaluations, and corrective actions for all components subject to AMR, with susceptible materials (e.g. steel, cast iron, and copper alloys with greater than 15 percent Zinc (Zn)), that may be adversely affected by some form of borated water leakage. This provides reasonable assurance that boric acid corrosion does not lead to degradation of pressure boundary, leakage boundary or structural integrity of components, supports, or structures, including electrical equipment in proximity to borated water systems.

The effects of boric acid corrosion on reactor coolant pressure boundary (RCPB) materials in the vicinity of nickel alloy components are also addressed by the PBN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP, which is associated with NUREG-2191 XI.M11B.

Additionally, this AMP relies in part on the PBN response to, and includes commitments to, NRC Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," to identify, evaluate, and correct borated water leaks that could cause corrosion damage. This AMP also includes provisions to initiate evaluations and assessments when leakage is discovered by activities not associated with the program. This AMP follows the guidance described in Section 7 of Westinghouse Commercial Atomic Power (WCAP)-15988-NP, Revision 2, "Generic Guidance for an Effective Boric Inspection Program for Pressurized Water Reactors."

16.2.2.5. Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

The PBN Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP is an existing AMP, previously the PBN Reactor Coolant System Alloy 600 Inspection Program, that manages the aging effect of primary water stress corrosion cracking (PWSCC) for pertinent nickel alloy materials (Alloy 600/82/182) in the RCS pressure boundary. This AMP also addresses the OE of degradation due to PWSCC of components or welds constructed from certain nickel alloys (e.g., Alloy 600/82/182) and exposed to pressurized water reactor primary coolant at elevated temperature. The scope of this AMP includes the following groups of components and materials: (a) all nickel alloy components and welds which are identified in EPRI MRP-126; (b) nickel alloy components and welds identified in ASME Code Cases N-770, N-729, and N-722, as incorporated by reference in 10 CFR 50.55a; and (c) components that are susceptible to corrosion by boric acid and may be impacted by leakage of boric acid from nearby or adjacent nickel alloy components previously described. This AMP is used in conjunction with the PBN Water Chemistry AMP because water chemistry can affect the cracking of nickel alloys.

For nickel alloy components and welds addressed by the regulatory requirements of

10 CFR 50.55a, inspections are conducted in accordance with 10 CFR 50.55a. Other nickel alloy components and welds within the scope of this program are inspected in accordance with EPRI MRP-126.

16.2.2.6. Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

The PBN Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP is a new AMP for the SPEO. This AMP augments the ASME Section XI inspections of reactor coolant system and connected components with service conditions above 482 °F, in order to detect the effects of loss of fracture toughness due to thermal aging embrittlement of CASS piping and piping components including pump casings. Thermal aging embrittlement susceptibility is based on the casting method, molybdenum content, and ferrite percentage. For potentially susceptible piping and piping components, aging management is accomplished either through enhanced volumetric examination, enhanced visual examination, or a component-specific flaw tolerance evaluation.

PBN has chosen the component-specific flaw tolerance evaluation method for aging management of Class 1 CASS components.

The Class 1 CASS components for PBN include valve bodies, reactor coolant pump (RCP) casings and reactor coolant system (RCS) main loop piping elbows.

Screening for significance of thermal aging embrittlement is not required for Class 1 CASS valve bodies per NUREG-2191. The existing ASME Code, Section XI inspection requirements are adequate.

RCP casings are constructed of CASS but are not susceptible to thermal aging embrittlement based on Table XI.M12-1 of NUREG-2191. However, an SLR Code Case N-481 RCP integrity analysis has also been performed. PBN is not using Code Case N-481 since it was annulled per RG 1.147. However, the analysis that supported annulling the Code Case was based on a 40-year plant life span. Thus, the flaw tolerance evaluation has been updated. Therefore, no further actions are needed to manage thermal aging embrittlement of the PBN RCP casings as the Code Case N-481 flaw tolerance evaluation has been revised to be applicable to 80 years.

For the Class 1 RCS main loop piping elbows, the component specific flaw tolerance evaluation has been updated for the 80-year SPEO as summarized in UFSAR Section 16.3.7.3.

16.2.2.7. Reactor Vessel Internals

The PBN Reactor Vessel Internals AMP is an existing AMP. The initial license renewal AMP was based on the inspection and evaluation guidelines of EPRI Technical Report No. 1022863 (MRP-227-A). However, the inspection and evaluation guidelines in MRP-227-A were written for an operating period of 60 years. This program uses the most recent guidelines of EPRI Technical Report No. 3002017168, MRP-227 Revision 1-A as the baseline to address an 80-year operating period. The guidelines in MRP-227 Revision 1-A are supplemented through a gap analysis that identifies enhancements to the program that are needed to address an 80-year operating period. The EPRI recommendations in

MRP 2018-022 “Interim Guidance for the Pressurized Water Reactor Internals Inspection and Evaluation Guidelines, MRP-227-A, for Subsequent License Renewal-Westinghouse and Combustion Engineering-Designed Reactor Vessel Internals” will provide the recommendations for this gap analysis. PBN will continue to implement inspection guidance updates from the industry Issues Programs to manage the aging of the reactor vessel internals. This program will be enhanced to implement MRP-227 Revision 1-A as supplemented by the gap analysis or an NRC-approved version of MRP-227 which addresses 80 years of operation if one is available prior to the SPEO. The resulting MRP-227 Revision 1-A program with enhancements identified by MRP 2018-022 is used to manage the applicable age-related degradation mechanisms, listed as follows:

(a) Cracking, including SCC, IASCC, primary water SCC (PWSCC), and cracking due to fatigue/cyclic loading;
(b) Loss of material induced by wear;
(c) Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement (IE);
(d) Changes in dimensions due to void swelling (VS) or distortion; and
(e) Loss of preload due to thermal and irradiation-enhanced stress relaxation and creep

16.2.2.8. Flow-Accelerated Corrosion

The PBN Flow-Accelerated Corrosion AMP is an existing AMP that manages wall thinning caused by flow-accelerated corrosion (FAC), as well as wall thinning due to erosion mechanisms.

This AMP predicts, detects, monitors, and mitigates FAC wear in high-energy carbon steel piping associated with the main steam and turbine generators, feedwater and blowdown systems. This AMP is based on industry guidelines (Nuclear Safety Analysis Center document, NSAC-202L-R4) and industry OE.

A predictive analytical software such as EPRI computer program CHECWORKS™ is used to predict component wear rates and remaining service life in the systems susceptible to FAC in order to provides reasonable assurance that structural integrity will be maintained between inspections.

The AMP includes (a) Identifying all FAC-susceptible piping systems and components; (b) Developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) Performing analyses of FAC models and, with consideration of OE, selecting a sample of components for inspections; (d) Inspecting components; (e) Evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) Incorporating inspection data to refine FAC models.

The PBN FAC AMP will also manage wall thinning caused by erosion mechanisms in limited situations where periodic monitoring is used in lieu of eliminating the cause, typically due to a design or operational deficiency. These limited situations are based on site OE and will be monitored similar to other FAC locations that are not modeled.

16.2.2.9. Bolting Integrity

The PBN Bolting Integrity AMP is an existing AMP that manages loss of preload, cracking, and loss of material for closure bolting for safety-related and nonsafety-related pressure-retaining components using preventive and inspection activities. This AMP also manages submerged pressure-retaining bolting and closure bolting for piping systems that contain air or gas for which leakage is difficult to detect. This AMP does not include the reactor head closure studs, HVAC closure bolting, reactor vessel internals bolting, bolting associated with electrical connections, or structural bolting, which are addressed by separate AMPs. This AMP relies on industry standards for comprehensive bolting maintenance as delineated in NUREG-1339, EPRI NP-5769, EPRI Report 1015336, and EPRI Report 1015337.

The preventive actions associated with this AMP include proper selection of bolting material; the use of appropriate lubricants and sealants in accordance with the guidelines of EPRI Report 1015336 and EPRI Report 1015337, along with additional recommendations from NUREG-1339; consideration of actual yield strength when procuring bolting material (e.g., ensuring any replacement or new pressure-retaining bolting has an actual yield strength of less than 150 ksi); lubricant selection (e.g., not allowing the use of molybdenum disulfide); proper torqueing of bolts, checking for uniformity of the gasket compression after assembly; and application of an appropriate preload based on guidance in EPRI documents, manufacturer recommendations, or engineering evaluation.

This AMP supplements the inspection activities required by ASME Code Section XI for ASME Code Class 1, 2 and 3 bolting. For ASME Code Class 1, 2, and 3, and non ASME Code class bolts, periodic system walkdowns and inspections are performed at least once per refueling cycle to provide reasonable assurance that indications of loss of preload (leakage), cracking, and loss of material are identified before leakage becomes excessive. Visual inspection methods and the frequency of inspection are selected to provide reasonable assurance that actions are taken to prevent significant age related degradation. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the PBN corrective action program (CAP). Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code.

Non-ASME Code inspections follow site procedures that include inspection parameters for items such as lighting and distance offset that provide an adequate examination. The inspection includes a representative sample of 20 percent of the population of bolt heads and threads (defined as bolts with the same material and environment combination) up to a maximum of 19 per unit considering the environments of Units 1 and 2 have been shown to be similar.

Submerged closure bolting that precludes detection of joint leakage is inspected visually for loss of material during maintenance activities. Bolt heads are inspected when made accessible and bolt threads are inspected when joints are disassembled. In each 10-year period during SPEO, a representative sample of bolt heads and threads is inspected. If opportunistic maintenance activities do not provide access to 20 percent of the population (for a material/environment combination) up to a maximum of up to a maximum of 19 bolts heads and threads per population at each unit, then the integrity of the bolted joint will be evaluated on a case-by-case basis using methods, such as periodic pump vibration measurements taken and trended or sump pump operator walkdowns performed to demonstrate that the pumps are appropriately maintaining sump levels.

Because leakage is difficult to detect for bolted joints that contain air or gas, the associated closure bolting will be evaluated on a case-by-case basis using one of the following methods:

- Inspections are performed consistent with that of submerged closure bolting;
- A visual inspection for discoloration is conducted (applies when leakage of the environment inside the piping systems would discolor the external surfaces);
- Monitoring and trending of pressure decay is performed when the bolted connection is located within an isolated boundary
- Soap bubble testing is performed; or
- Thermography testing is performed (applies when the temperature of the fluid is higher than ambient conditions).

For component joints that are not normally pressurized, the aging effects associated with closure bolting will be managed by checking the torque to the extent that the closure bolting is not loose.

Indications of aging are evaluated in accordance with Section XI of the ASME Code. Leaking joints do not meet acceptance criteria

16.2.2.10. Steam Generators

The PBN Steam Generators AMP, previously the PBN Steam Generator Integrity program, is an existing AMP that manages the aging of steam generator tubes, plugs, divider plate assemblies, heads (interior surfaces of channel or lower heads), tubesheet(s) (primary side), and secondary side components that are contained within the steam generator (i.e., secondary side internals). However, the tube-to-tubesheet welds of the PBN Unit 1 steam generators are exempt from inspection and monitoring per the NRC Safety Evaluation Report (SER) (Point Beach Unit 1 – Issuance of Amendment Regarding Permanent Alternative Repair Criteria for Steam Generator Tubes, Accession Number ML17159A778, July 27, 2017) for permanent Alternate Repair Criteria (H*) for steam generator tubes.

The aging of steam generator pressure vessel welds is managed by other AMPs, such as the PBN ASME Section XI ISI, Subsections IWB, IWC, and IWD, AMP (Section 16.2.2.1) and the PBN Water Chemistry AMP (Section 16.2.2.2).

The establishment of a steam generator program for ensuring steam generator tube integrity is required by the PBN Technical Specifications. Additionally, administrative controls require tube integrity to be maintained to specific performance criteria, condition monitoring requirements, inspection scope and frequency, acceptance criteria for the plugging or repair of flawed tubes, acceptable tube repair methods, and leakage monitoring requirements. The nondestructive examination (NDE) techniques used to inspect steam generator components covered by this AMP are intended to identify components (e.g., tubes, plugs) with degradation that may need to be removed from service (e.g., tubes), repaired, or replaced, as appropriate.

The AMP is modeled after NEI 97-06, “Steam Generator Program Guidelines” and incorporates the referenced EPRI Guidelines of NEI 97-06.

Volumetric inspections are performed on steam generator tubes to identify degradation such as primary water stress corrosion cracking (PWSCC), outer diameter stress corrosion cracking (ODSCC), and loss of material due to foreign objects and tube support structures. General visual inspections are also performed to identify any evidence of cracking, loss of material or corrosion where accessible. The AMP includes a degradation assessment to determine the type and location of flaws to which the tube may be susceptible, and implementation of inspection methods capable of detecting those forms of degradation are addressed.

This AMP also performs general visual inspections of the steam generator heads (internal surfaces) looking for evidence of cracking or loss of material (e.g., rust stains). Additionally, the AMP includes foreign material exclusion as a means to inhibit wear degradation, and secondary side maintenance activities, such as sludge lancing, for removing deposits that may contribute to component degradation.

16.2.2.11. Open-Cycle Cooling Water System

The PBN Open-Cycle Cooling Water System AMP is an existing AMP, previously known as the Open Cycle Cooling (Service) Water System Surveillance Program, that manages aging effects caused by exposure of internal surfaces of metallic components in water systems (e.g., piping, piping components, valves, piping elements, and heat exchangers) to raw, untreated (e.g., service) water. The PBN Open-Cycle Cooling Water System AMP relies, in part, on implementing the response to NRC Generic Letter (GL) 89-13, “Service Water System Problems Affecting Safety-Related Equipment” and subsequent commitment changes. This AMP manages aging effects through: (a) surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of heat exchangers, and (c) routine inspection and maintenance so that corrosion, erosion, protective coating failure, fouling, and biofouling cannot degrade the performance of systems serviced by the open-cycle cooling water (service water) system. Inspection methods include visual, ultrasonic testing (UT), eddy current testing (ECT), and radiography. This AMP also includes enhancements to the guidance in NRC GL 89-13 that address OE such that aging effects are adequately managed.

16.2.2.12. Closed Treated Water Systems

The PBN Closed Treated Water Systems AMP, previously known as the Closed-Cycle Cooling Water System Surveillance Program, is an existing AMP and is a mitigation program that also includes condition monitoring to verify the effectiveness of the mitigation activities. This AMP manages aging effects in closed cycle cooling water systems that are not subject to significant sources of contamination, in which water chemistry is controlled and heat is not directly rejected to the ultimate heat sink. This AMP consists of: (a) water treatment, including the use of corrosion inhibitors, which also act as a biocide, to modify the chemical composition of the water such that the effects of corrosion and microbiological activity are minimized; (b) chemical testing of the water so that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation. Inspection methods include visual, UT and ECT testing. The PBN Closed Treated Water Systems AMP uses as applicable, EPRI TR-3002000590, Revision 2, "Closed Cooling Water Chemistry Guideline." EPRI TR-3002000590 is used rather than the NUREG-2191 recommended standard, EPRI 1007820, because EPRI TR-3002000590 supersedes EPRI 1007820. The newer EPRI guideline document encompasses new technology and captures lessons learned and industry OE.

16.2.2.13. Inspection of Overhead Heavy Load Handling Systems

The PBN Inspection of Overhead Heavy Load Handling Systems AMP (referred to herein as the "PBN XI.M23 AMP") is an existing AMP that is currently implemented as part of the PBN Structures Monitoring Program. The PBN XI.M23 AMP was evaluated as a portion of the PBN Structures Monitoring AMP in the initial license renewal application. The PBN XI.M23 AMP is evaluated separately in the SLRA and it is compared to the NUREG-2191, Section XI.M23 program. This AMP evaluates the effectiveness of maintenance monitoring activities for cranes and hoists that are within the scope of SLR. This AMP also addresses the inspection and monitoring of crane-related structures and components to provide reasonable assurance that the handling system does not affect the intended function of nearby safety-related equipment. This AMP includes periodic visual inspections and examination of accessible surfaces to detect loss of material due to corrosion, deformation, and wear, cracking, and indications of loss of preload for load handling bridges, structural members, structural components, and bolted connections. This AMP also includes corrective actions as required based on these inspections. This AMP relies on the guidance in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," ASME B30.2, "Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)," and other appropriate standards in the ASME B30 series. These cranes also comply with the maintenance rule requirements provided in 10 CFR 50.65 (Reference 1.6.46).

16.2.2.14. Compressed Air Monitoring

The PBN Compressed Air Monitoring AMP is an existing AMP which monitors moisture content and contaminants in Instrument Air and will perform opportunistic visual inspections of internal surfaces for loss of material. The following systems are in scope for the PBN Compressed Air Monitoring AMP:

- Instrument Air sub-system of the Plant Air System
- Diesel Starting Air sub-system (Train B only) of the Emergency Power System
- Gas Turbine Generator Instrument and Control Air sub-system of the Emergency Power System

The PBN Compressed Air Monitoring AMP also manages components which supply instrument air to the Containment Ventilation System, Main and Auxiliary Steam System, Feedwater and Condensate System, Auxiliary Feedwater System, and Containment Isolation System.

The PBN Compressed Air Monitoring AMP includes preventive monitoring of water (moisture), and other contaminants (particulate size and lubricant content) to keep within specified limits.

The PBN Compressed Air Monitoring AMP is based on the relevant aspects of the PBN response to NRC GL 88-14 and INPO SOER 88-01. The PBN Compressed Air Monitoring AMP incorporates the guidance from the most current ANSI/ISA standards, and will incorporate the guidance from the ASME OM-2012, Division 2, Part 28, and EPRI TR-10847 for testing and monitoring air quality and moisture. Opportunistic visual inspections of components for indications of loss of material due to corrosion will be performed. Additionally, inspection and test results are trended to provide for the timely detection of aging effects prior to loss of intended function.

16.2.2.15. Fire Protection

The PBN Fire Protection AMP is an existing AMP, formerly a portion of the PBN Fire Protection Program. This AMP manages aging effects (loss of material, cracking, and loss of seal) associated with fire barriers and non-water suppression systems (halon and dry chemical systems). The PBN Fire Protection AMP includes fire barrier inspections. The fire barrier inspection portion of this AMP requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, floors, fire damper assemblies, electrical raceway fire barrier systems, well-sealed robustly secured components, fully enclosed cable tray covers, fire proofing material sprayed onto structural steel, as well as periodic visual inspection and functional tests of fire-rated doors so that their operability is maintained. The PBN Fire Protection AMP also requires periodic visual inspection of other passive fire protection features credited for the Fire Protection Program like oil collection channels, trenches, and skids. The PBN Fire Protection AMP includes periodic inspection and testing of the halon fire suppression systems and dry chemical fire extinguishing systems. See FSAR Section 9.10 for additional information on the PBN Fire Protection Program.

With respect to preventive actions, PBN has adopted the National Fire Protection Association (NFPA) 805 fire protection program to meet the requirements of 10 CFR 50.48(c) and ensure that regulatory requirements are met for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability for each fire area containing SSCs important to safety.

Inspection results are acceptable if there are no signs of degradation that could result in the loss of the fire protection capability due to loss of material or elastomer degradation. The acceptance criteria include:

(a) No visual indications (outside of those allowed by approved penetration seal configurations) of cracking, separation of seals from structures and components, indications of increased hardness, shrinkage, loss of strength, or ruptures or punctures of seals;
(b) No significant indications of cracking, loss of material, and changes to elastomer properties of fire barrier walls, ceilings, floors, passive fire protection features credited by the fire protection program, and in other fire barrier materials;
(c) No visual indication of loss of material on fire damper assemblies;
(d) No visual indications of missing parts, holes, and wear; and

(e) No deficiencies in the functional tests of fire doors (i.e., the door swings easily, freely, and achieves positive latching).

Periodic inspections and testing of the halon fire suppression systems and dry chemical fire extinguishing systems are performed to demonstrate that it is functional, and the surface condition of components is inspected for corrosion, nozzle obstructions, and other damage.

Visual inspection of at least 10 percent of each type of sealed penetration is performed at a frequency of every 18 months, which is in accordance with the NRC-approved fire protection program. Visual inspections on fire-rated structures (fire barrier walls, ceilings, and floors) are conducted at a frequency of at least once every five years. Visual inspections on combustible liquid spill retaining features (oil collection channels, trenches, and skids) are conducted at a frequency of at least once every 18 months. Visual inspections of fire-rated assemblies (electrical raceway fire barrier systems, well-sealed robustly secured components, fully enclosed cable tray covers, and fire proofing material sprayed onto structural steel) are conducted at a frequency of at least once every 54 months (approximately 33 percent of each type per refueling cycle). Periodic visual inspections and functional tests are conducted on fire doors and their closing mechanism and latches are verified functional at least once per 6 months. Visual inspection on 10 percent of the fire damper assemblies are conducted at a frequency of once every 18 months, which is in accordance with the NRC-approved fire protection program.

The results of inspections and functional testing of the in-scope fire protection equipment are collected, analyzed, and summarized by engineers in health reports. The system and program health reporting procedures identify adverse trends and prescribe preemptive corrective actions to prevent further degradation or future failures. When performance degrades to unacceptable levels, the PBN CAP is utilized to drive improvement. During the inspection of penetration seals and fire damper assemblies, if any sign of abnormal degradation is detected within the sample, the inspection sample size is expanded, in accordance with the approved PBN fire protection program, to include an additional 10 percent of each type of sealed penetration or fire damper assembly.

16.2.2.16. Fire Water System

The PBN Fire Water System AMP is an existing AMP, formerly part of the PBN Fire Protection Program. This AMP manages aging effects associated with water-based fire protection system components. This AMP manages loss of material, cracking, and flow blockage due to fouling by conducting periodic visual inspections, tests, and flushes performed in accordance with the 2011 Edition of NFPA 25. Testing or replacement of sprinklers that have been in place for 50 years is performed in accordance with NFPA 25. In addition to NFPA codes and standards, portions of the water-based fire protection system that are: (a) normally dry but periodically subjected to flow and (b) cannot be drained or allow water to collect are subjected to augmented testing beyond that specified in NFPA 25, including: (a) periodic system full flow tests at the design pressure and flow rate or internal visual inspections and (b) piping volumetric wall-thickness examinations. Preventive actions (i.e., periodic flushes and biocide utilization) as well as periodic maintenance, testing, and inspection activities of the water-based fire protection systems are implemented to provide reasonable assurance that the fire water systems are capable of performing their intended function. Inspections and testing are performed in accordance with the nuclear insurance carrier's fire protection system testing requirements and generally follows the guidance of applicable NFPA Codes and Standards.

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions are initiated. Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of sufficient organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material is removed, the source of the material is identified, and the source is corrected. Inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes for an adequate examination.

16.2.2.17. Outdoor and Large Atmospheric Metallic Storage Tanks

The PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP is an existing AMP, previously known as the Tank Internal Inspection Program. This condition monitoring AMP manages aging effects associated with outdoor tanks sited on concrete and indoor large-volume tanks containing water designed with internal pressures approximating atmospheric pressure that are sited on concrete. The tanks included within the scope of this AMP are as follows:

- 1T-013, Refueling Water Storage Tank (RWST)
- 2T-013, Refueling Water Storage Tank (RWST)
- T-021, Reactor Makeup Water Tank (RMWT)
- T-032A, Fuel Oil Storage Tank (FOST)
- T-032B, Fuel Oil Storage Tank (FOST)

This AMP includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice. This AMP manages loss of material and cracking by conducting periodic internal and external visual and surface examinations. Surface exams are conducted to detect cracking when susceptible materials are used. Thickness measurements of tank bottoms are conducted to detect degradation. The external surfaces of insulated tanks are periodically inspected using a sampling of inspection points. Inspections are conducted in accordance with ASME Code Section XI requirements as applicable or are conducted in accordance with plant-specific procedures that include inspection parameters such as lighting, distance, offset, and surface conditions.

16.2.2.18. Fuel Oil Chemistry

The PBN Fuel Oil Chemistry AMP is an existing AMP, previously known as the Fuel Oil Chemistry Control Program, that manages loss of material in tanks, components, and piping exposed to an environment of diesel fuel oil. This AMP includes (a) surveillance and maintenance procedures to mitigate corrosion, and periodic and/or conditional visual inspections of internal surfaces and/or wall thickness measurements (e.g., by UT) from the external surfaces of fuel oil tanks, and (b) measures to verify the effectiveness of the mitigative actions and confirm the insignificance of an aging effect. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the PBN Technical Specifications. Guidelines of ASTM Standards, such as ASTM D 0975, D 2709, D 6217, and D 4057 are also used when applicable. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic cleaning/draining of tanks and by verifying the quality of new fuel oil before its introduction into the storage tanks.

The effectiveness of the fuel oil chemistry controls is verified through one-time inspections of a representative sample of components in systems that contain fuel oil in accordance with the PBN One-Time Inspection AMP.

16.2.2.19. Reactor Vessel Material Surveillance

The PBN Reactor Vessel Material Surveillance AMP is an existing AMP formerly a portion of the PBN Reactor Vessel Integrity Program. This AMP includes withdrawal and testing of the Supplemental “A” surveillance capsule, identified in TRM 2.2. This capsule will receive between one to two times the peak reactor vessel neutron fluence of interest at the end of the SPEO in the TLAAs for USE, PTS, and P-T temperature limits. The surveillance program adheres to the requirements of 10 CFR Part 50, Appendix H, as well as the American Society for Testing Materials (ASTM) standards incorporated by reference in 10 CFR Part 50, Appendix H. Surveillance capsules are designed and located to permit insertion of replacement capsules.

10 CFR Part 50, Appendix H, requires implementation of a reactor vessel material surveillance program when the peak neutron fluence at the end of the design life of the vessel is projected to exceed 10^{17} n/cm^2 (E > 1 MeV). The purpose of the PBN Reactor Vessel Material Surveillance AMP is to monitor the changes in fracture toughness to the ferritic reactor vessel beltline materials. As described in RIS 2014-11, beltline materials are those ferritic reactor vessel materials with a projected neutron fluence greater than 10^{17} n/cm^2 (E > 1 MeV) at the end of the license period (for example, the SPEO), which are evaluated to identify the extent of neutron radiation embrittlement for the material. The surveillance capsules contain reactor vessel material specimens and are located near the inside vessel wall in the beltline region so that the material specimens duplicate, to the greatest degree possible, the neutron spectrum, temperature history, and maximum neutron fluence experienced at the reactor vessel’s inner surface. Because of the resulting lead factors, surveillance capsules receive equivalent neutron fluence exposures earlier than the inner surface of the reactor vessel. This allows surveillance capsules to be withdrawn prior to the inner surface receiving an equivalent neutron fluence and therefore test results bound the corresponding operating period in the capsule withdrawal schedule.

Surveillance capsules are designed and located to permit insertion of replacement capsules. If standby capsules will be incorporated into the Appendix H program for the SPEO and have been removed from the reactor vessel, these should be reinserted so that appropriate lead factors are maintained and test results will bound the corresponding operating period. This program includes removal and testing of at least one capsule with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the SPEO.

PBN was a member of the Babcock and Wilcox Owners Group (B&WOG) reactor vessel working group. The B&WOG designed an irradiation surveillance program (Master Integrated Reactor Vessel Program, MIRVP) in which member materials are irradiated at host plants. The MIRVP Charpy values and direct fracture toughness (master curve) data are used as supplemental data. The PWROG is now the mechanism for the previous B&WOG reactor vessel working group activities. The implementation of the MIRVP in the PBN Reactor Vessel Material Surveillance AMP is only for supplemental data and is not a part of the NRC approved surveillance program. Therefore, this AMP relies fully on onsite capsules.

The objective of the PBN Reactor Vessel Material Surveillance program is to provide sufficient material data and dosimetry to (a) monitor irradiation embrittlement to neutron fluences greater than the projected neutron fluence at the end of the SPEO, and (b) provide adequate dosimetry monitoring during the SPEO. Dosimetry monitoring during the SPEO is performed as described in the PBN Neutron Fluence Monitoring AMP.

This program is a condition monitoring program that measures the increase in Charpy V-notch 30 ft-lb transition temperature and the drop in the upper-shelf energy as a function of neutron fluence and irradiation temperature. The data from this surveillance program are used to monitor neutron irradiation embrittlement of the reactor vessel and are inputs to the neutron embrittlement TLAAs. The PBN Reactor Vessel Material Surveillance program is also used in conjunction with the PBN Neutron Fluence Monitoring AMP which monitors neutron fluence for reactor vessel components and reactor vessel internal components.

In accordance with 10 CFR Part 50, Appendix H, all surveillance capsules, including those previously removed from the reactor vessel, meet the test procedures and reporting requirements of ASTM E 185-82, to the extent practicable, for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including the conversion of standby capsules into the Appendix H program and extension of the surveillance program for the SPEO, must be approved by the NRC prior to implementation, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3. Standby capsules placed in storage (e.g., removed from the reactor vessel) are maintained for possible future insertion.

16.2.2.20. One-Time Inspection

The PBN One-Time Inspection AMP is an existing AMP consisting of a one-time inspection of selected components to verify: (a) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the SPEO; (b) the insignificance of an aging effect; and (c) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

The elements of the PBN One-Time Inspection AMP include: (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and OE, (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (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) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the SPEO. The inspection sample includes locations where the most severe aging effect(s) would be expected to occur. Inspection methods may include visual (or remote visual), surface or volumetric examinations, or other established NDE techniques.

The inspection includes a representative sample of each population (defined as components having the same material, environment, and aging effect combination) and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. A representative sample size is 20 percent of the population or a maximum of 25 components at each unit. Otherwise, a technical justification of the methodology and sample size used for selecting components for one-time inspection is included as part of the program documentation. Factors that will be considered when choosing components for inspection are time in service, severity of operating conditions, and OE.

The PBN One-Time Inspection AMP will also perform inspections on the Unit 1 steam generator divider plate assemblies and the steam generator circumferential transition cone field welds on both units in order to verify the effectiveness of the PBN Water Chemistry AMP.

The PBN One-Time Inspection AMP is used to verify the effectiveness of the PBN Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis AMPs. For steel components exposed to water environments that do not include corrosion inhibitors as a preventive action (e.g., treated water, treated borated water, raw water, waste water), the program is used to verify that long-term loss of material due to general corrosion will not cause a loss of intended function [e.g., pressure boundary, leakage boundary (spatial), structural integrity (attached)].

The PBN One-Time Inspection AMP is not used for structures or components with known age-related degradation mechanisms or when the environment in the SPEO is not expected to be equivalent to that in the prior operating period. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

16.2.2.21. Selective Leaching

The PBN Selective Leaching AMP is a new AMP that includes inspections of components that may be susceptible to loss of material due to selective leaching by demonstrating the absence of selective leaching (dealloying) of materials. The scope of this AMP includes components constructed of gray cast iron, ductile iron, and copper alloys (except for inhibited brass) containing greater than 15 percent zinc or greater than 8 percent aluminum in susceptible environments. One-time inspections for components exposed to a closed-cycle cooling water or treated water environment will be conducted, based on PBN plant-specific OE which has not revealed selective leaching in these environments. Opportunistic and periodic inspections will be conducted for raw water, waste water, soil, and groundwater environments. Visual inspections coupled with mechanical examination techniques such as chipping or scraping will be conducted. Periodic destructive examinations of components for physical properties (i.e., degree of dealloying, depth of dealloying, through-wall thickness, and chemical composition) will be conducted for components exposed to raw water, waste water, soil, and groundwater environments. Inspections and tests will be conducted to determine whether loss of material will affect the ability of the components to perform their intended function for the SPEO. Inspections will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions.

Each of the one-time and periodic inspections for these material and environment populations at each unit comprises a 3 percent sample or a maximum of 10 components. For each material and environment population with 35 or more components, two destructive examinations will be performed in each 10-year inspection interval at each unit. For each population with less than 35 susceptible components, one destructive examination will be performed in each 10-year inspection interval at each unit.

When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the SPEO, additional inspections will be performed if the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of additional inspections is equal to the number of failed inspections for each material and environment population, with a minimum of five additional visual and mechanical inspections when visual and mechanical inspection(s) did not meet acceptance criteria, or 20 percent of each applicable material and environment combination is inspected, whichever is less, and a minimum of one additional destructive examination when destruction examination(s) did not meet acceptance criteria.

16.2.2.22. ASME Code Class 1 Small-Bore Piping

The PBN ASME Code Class 1 Small-Bore Piping AMP is an existing AMP that augments the existing ASME Code, Section XI requirements and is applicable to small-bore ASME Code Class 1 piping and systems with an NPS diameter less than 4 inches and greater than or equal to 1 inch. This AMP provides a one-time volumetric inspection of a sample of this Class 1 piping and includes full and partial penetration (socket) welds. The AMP includes measures to verify that degradation is not occurring, thereby confirming that there is no need to manage aging-related degradation. The PBN ASME Code Class 1 Small-Bore Piping AMP includes locations that are susceptible to stress corrosion cracking and cracking due to thermal or vibratory fatigue loading. Such cracking is frequently initiated from the inside diameter of the piping; therefore, volumetric examinations are needed to detect cracks.

Volumetric inspections of a sample (sample size as specified in NUREG-2191, Table XI.M35-1) of small-bore Class 1 piping and nozzles are performed to determine if cracking is an aging effect requiring management during the SPEO. Per NUREG-2191, Table XI.M35-1, PBN is a Category A plant because it has no history of age-related cracking. Per Category A, the inspection will be a one-time inspection with a sample size of at least 3 percent, up to a maximum of 10 welds, of each weld type, for each operating unit using a methodology to select the most susceptible and risk-significant welds. For socket welds, destructive examination may be performed in lieu of volumetric examinations. Because more information can be obtained from a destructive examination than from nondestructive examination, credit will be taken for each weld destructively examined equivalent to having volumetrically examined two welds. Based on the results of these inspections, the need for additional inspections or programmatic corrective actions is then established.

The measure of effectiveness this AMP considers that: (1) the one-time inspection sampling is statistically significant; (2) samples will be selected as described NUREG-2191, XI.M35; and (3) no repeated failures occur over an extended period of time. Should evidence of cracking be revealed by a one-time inspection, a periodic inspection is also proposed, as managed by a plant-specific AMP.

16.2.2.23. External Surfaces Monitoring of Mechanical Components

The PBN External Surfaces Monitoring of Mechanical Components AMP is an existing AMP that was formerly the PBN Systems Monitoring Program.

The PBN External Surfaces Monitoring of Mechanical Components AMP manages loss of material, cracking, hardening or loss of strength (of elastomeric components), reduction of heat transfer due to fouling (air to fluid heat exchangers), loss of preload of HVAC closure bolting, and reduction of thermal insulation resistance due to moisture intrusion.

The PBN External Surfaces Monitoring of Mechanical Components AMP also inspects the integrity of coated surfaces as an effective method for managing the effects of corrosion on the metallic surfaces. This AMP provides for periodic visual inspection and examination for degradation of accessible surfaces of specific SSCs, and corrective actions, as required, based on these inspections.

Periodic visual inspections, not to exceed a refueling outage interval, of metallic, polymeric, and insulation jacketing (insulation when not jacketed) are conducted. Surface examinations or ASME Code Section XI VT-1 examinations (including those inspections conducted on non-ASME Code components) are conducted to detect cracking of stainless steel (SS) and aluminum components.

For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength or reduction in impact strength is used to augment the visual examinations conducted under the PBN External Surfaces Monitoring of Mechanical Components AMP. A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point) are periodically inspected every 10 years during the SPEO.

Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with site-specific procedures, including inspection parameters such as lighting, distance, offset, and surface conditions.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the SPEO. Qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions.

16.2.2.24. Flux Thimble Tube Inspection

The PBN Flux Thimble Tube Inspection AMP is an existing AMP that was formerly the PBN Thimble Tube Inspection Program. This AMP is a condition monitoring program that is used to inspect for thinning of the flux thimble tube wall, which provides a path for the incore neutron flux monitoring system detectors and forms part of the RCS pressure boundary. This AMP manages the aging effect of material loss due to fretting wear.

The flux thimble tube inspection associated with this AMP encompasses all of the flux thimble tubes that form part of the RCS pressure boundary. This AMP monitors flux thimble tube wall thickness to detect loss of material from the flux thimble tubes during the SPEO. The 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. Periodic eddy current testing (ECT) is used to monitor for loss of material and wear of the flux thimble tubes during the SPEO. This inspection AMP implements the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors."

16.2.2.25. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new AMP that will manage loss of material, cracking, reduction of heat transfer due to fouling, flow blockage, and hardening or loss of strength of polymeric materials. Applicable environments will include air, gas, condensation, diesel exhaust, water, fuel oil, and lubricating oil. Some inspections and activities within the scope of the new AMP were previously performed by the PBN Periodic Surveillance and Preventive Maintenance Program.

The AMP will consist of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components. Surface examinations or ASME Code Section XI VT-1 examinations will be conducted to detect cracking of stainless steel and aluminum components. Aging effects associated with items (except for elastomers) within the scope of the PBN Open-Cycle Cooling Water AMP, the PBN Closed Treated Water Systems AMP, and the PBN Fire Water System AMP are not managed by this AMP. This AMP will not manage components in which recurring internal corrosion is evident based on a search of site-specific OE conducted during the SLRA development.

Internal inspections will be performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the SPEO a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or maximum of 19 components per unit will be inspected for the in-scope aging effects. The maximum of 19 components per unit for inspection will be used in lieu of 25 components per unit due to PBN being a two-unit plant with sufficiently similar operating conditions at each unit (e.g., flowrate, chemistry, temperature, and excursions), similar time in operation for each unit, similar water sources, and similar operating frequency.

Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections will continue in each period despite meeting the sampling limit. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program. If visual inspection of internal surfaces is not possible, a plant-specific program will be used.

Internal visual inspections used to assess loss of material will be capable of detecting surface irregularities that could be indicative of an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected for steel components exposed to raw water, raw water (potable), or waste water, follow-up volumetric examinations will be performed.

Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions. Acceptance criteria will be such that the component will meet its intended function until the next inspection or the end of the SPEO. Qualitative acceptance criteria will be clear enough to reasonably assure a singular decision is derived based on observed conditions. Corrective actions will be performed as required based on the inspections results.

16.2.2.26. Lubricating Oil Analysis

The PBN Lubricating Oil Analysis AMP is an existing AMP, previously performed as part of PBN's predictive maintenance activities. The purpose of this AMP is to provide reasonable assurance that the oil environment in mechanical systems is maintained to the required quality to prevent or mitigate age-related degradation of components within the scope of the AMP. The PBN Lubricating Oil Analysis AMP maintains lubricating oil and hydraulic oil system contaminants (water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. Testing activities include sampling and analysis of lubricating oil for contaminants which could be indicative of in-leakage and corrosion product buildup.

The effectiveness of the PBN Lubricating Oil Analysis AMP will be validated by the results of inspections completed under the PBN One-Time Inspection AMP.

16.2.2.27. Buried and Underground Piping and Tanks

The PBN Buried and Underground Piping and Tanks AMP, previously known as the Buried Services Monitoring Program, is an existing AMP that manages the aging effects associated with the external surfaces of buried and underground piping and tanks such as loss of material and cracking. It addresses piping and tanks composed of metallic (carbon steel, low-alloy steel, and cast iron) materials that are within the scope of Subsequent License Renewal in the service water, fuel oil, and fire water systems. Loss of material is monitored by visual inspection of the exterior and wall thickness measurements of the piping. Wall thickness is determined by an NDE technique such as UT.

The AMP also manages aging through preventive and mitigative actions (i.e., coatings, backfill quality, and cathodic protection). The number of inspections is based on the effectiveness of the preventive and mitigative actions. Annual cathodic protection surveys will be conducted. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off potential (i.e., the electrode's polarized half-cell potential taken immediately after stopping the cathodic protection current), loss of material rates are measured.

Visual inspections of external surfaces of buried components are performed to check for evidence of coating/wrapping damage, loss of material, and cracking. The periodicity of these inspections will be based on plant OE and opportunities for inspection such as scheduled maintenance work but will be performed at a minimum of once every 10 years during the SPEO. Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the SPEO, an increase in the sample size is conducted.

Based on the PBN OE and the preventive design features in place, the buried steel piping at PBN meets the criteria for Preventive Action Category C. Thus, the number of inspections for each 10-year inspection period, commencing 10 years prior to the SPEO, based on the inspection quantities identified in GALL-SLR Table XI.M41-2 (adjusted for a 2-unit plant site) is two.

16.2.2.28. Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP that manages degradation of internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, lubricating oil, fuel oil, air, or condensation that can lead to loss of material of base materials or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris. The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is not used to manage loss of coating integrity for external coatings. The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP performs inspections of coatings/linings applied to components which are managed by the PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP, the PBN Fuel Oil Chemistry AMP, the PBN Open-Cycle Cooling Water AMP, the PBN Closed Treated Water Systems AMP, and the PBN Fire Water System AMP.

The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP manages these aging effects for internal coatings by conducting opportunistic and periodic visual inspections of coatings/linings applied to the internal surfaces of in-scope components where loss of coating or lining integrity could impact the component's or downstream component's CLB intended function(s). Where visual inspection of the coated/lined internal surfaces determines the coating/lining is deficient or degraded, physical tests are performed, where physically possible, in conjunction with the visual inspection.

For tanks and heat exchangers, all accessible surfaces are inspected. Piping inspections are sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard. For cementitious coatings/linings inspectors should have a minimum of 5 years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of 1 year of experience. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist with the blisters being surrounded by sound material and with the size and frequency not increasing. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining. Additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment.

16.2.2.29. ASME Section XI, Subsection IWE

The PBN ASME Section XI, Subsection IWE AMP is an existing AMP that was formerly part of the ASME Section XI, Subsections IWE and IWL Inservice Inspection AMP. This condition monitoring AMP is in accordance with ASME Code Section XI, Subsection IWE, and consistent with 10 CFR 50.55a, "Codes and Standards," with supplemental recommendations. This program will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC in accordance with 10 CFR 50.55a prior to implementation.

The AMP includes periodic visual, surface, and volumetric examinations, where applicable, of the steel liner of each concrete containment and their integral attachments for signs of degradation, damage, irregularities including discernable liner plate bulges, and for coated areas distress of the underlying metal shell or liner, and corrective actions. Acceptability of inaccessible areas of steel containment shell or concrete containment steel liner is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas.

If triggered by plant-specific OE, a one-time supplemental volumetric examination will be performed by sampling randomly-selected as well as focused locations susceptible to loss of thickness due to corrosion of containment shell or liner that is inaccessible from one side. Inspection results are compared with prior recorded results in acceptance of components for continued service.

16.2.2.30. ASME Section XI, Subsection IWL

The PBN ASME Section XI, Subsection IWL AMP is an existing AMP that was formerly part of the ASME Section XI, Subsections IWE and IWL Inservice Inspection Program. This AMP is performed in accordance with ASME Code Section XI, Subsection IWL, and consistent with 10 CFR 50.55a "Codes and Standards," with supplemental recommendations. This program will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC in accordance with 10 CFR 50.55a prior to implementation.

This AMP consists of: (a) periodic visual inspection of concrete surfaces for the pre-stressed concrete containments, (b) periodic visual inspection and sample tendon testing of un-bonded post-tensioning systems for prestressed concrete containments for signs of degradation, assessment of damage, and corrective actions, and testing of the tendon corrosion protection medium and free water. Measured tendon lift-off forces are compared to predicted tendon forces calculated in accordance with Regulatory Guide 1.35.1 as addressed in PBN AMP X.S1, “Concrete Containment Unbonded Tendon Prestress.” The Subsection IWL requirements are supplemented to include quantitative acceptance criteria for evaluation of concrete surfaces based on the “Evaluation Criteria” provided in Chapter 5 of ACI 349.3R.

This program manages aging effects for reinforced concrete containments and unbonded post-tensioning systems, which are inspected in accordance with ASME Section XI, Subsection IWL.

16.2.2.31. ASME Section XI, Subsection IWF

The PBN ASME Section XI, Subsection IWF AMP is an existing AMP that manages aging effects for Class 1, 2, and 3 component supports. The primary inspection method employed is visual examination. Criteria for acceptance and corrective action are in accordance with ASME Section XI, Subsection IWF. Degradation that potentially compromises the function or load capacity of the support, including bolting, is identified for evaluation. Supports requiring corrective action are re-examined during the next inspection period. This program will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC in accordance with 10 CFR 50.55a prior to implementation.

This program consists of periodic visual examination of piping and component supports for signs of degradation, evaluation, and corrective actions. This program recommends additional inspections beyond the inspections required by the

10 CFR 50.55a ASME Code Section XI, Subsection IWF program. This consists of a one-time inspection of an additional five percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. This one-time inspection is conducted within 5 years prior to entering the SPEO. For high-strength bolting in sizes greater than one inch nominal diameter, volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 should be performed to detect cracking in addition to the VT-3 examination.

If a component support does not exceed the acceptance standards of IWF-3400 but is electively repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

16.2.2.32. 10 CFR Part 50, Appendix J

The PBN 10 CFR Part 50, Appendix J, AMP is an existing AMP that was formerly part of the ASME Section XI, Subsections IWE and IWL Inservice Inspection AMP. The Appendix J AMP is a performance monitoring program that monitors leakage rates through the containment, including the containment shell or liner, associated welds, penetrations, isolation valves, fittings, and other access openings, in order to detect degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. This program is implemented in accordance with 10 CFR Part 50 Appendix J, NEI 94-01, and is subject to the requirements of 10 CFR Part 54. PBN technical specifications were updated in 2018 to replace RG 1.163 with NEI 94-01 Revision 3-A and the conditions and limitations specified in NEI 94-01 Revision 2-A as discussed in the Appendix J Testing Program. Additionally, 10 CFR 50, Appendix J, requires a general visual inspection of the accessible interior and exterior surfaces of the containment structures and components to be performed prior to any Type A test and at periodic intervals between tests based on the performance of the containment system.

16.2.2.33. Masonry Walls

The PBN Masonry Walls AMP is an existing AMP that is currently implemented as part of the PBN Structures Monitoring Program. The PBN Masonry Walls AMP was evaluated as a portion of the PBN Structures Monitoring AMP in the initial license renewal application. The PBN Masonry Walls AMP is evaluated separately in the subsequent license renewal application and it is compared to the NUREG-2191, Section XI.S5 program. This condition monitoring AMP is based on NRC Inspection and Enforcement (IE) Bulletin 80-11, “Masonry Wall Design,” and monitoring proposed by NRC Information Notice (IN) 87-67, “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE 80-11,” for managing shrinkage, separation, gaps, loss of material and cracking of masonry walls such that the evaluation basis is not invalidated and intended functions are maintained.

This AMP consists of periodic visual inspection of masonry walls within the scope of SLR to detect loss of material and cracking of masonry units and mortar. Masonry walls that are fire barriers are also managed by the Fire Protection program.

16.2.2.34. Structures Monitoring

The PBN Structures Monitoring AMP is an existing AMP that consists of periodic visual inspection and monitoring of the condition of concrete and steel structures, structural components, component supports, and structural commodities to ensure that aging degradation (such as those described in ACI 349.3R, ACI 201.1R, SEI/ASCE 11, and other documents) will be detected, the extent of degradation determined and evaluated, and corrective actions taken prior to loss of intended functions. Structures are monitored on an interval not to exceed 5 years. Inspections also include seismic joint fillers, elastomeric materials; steel edge supports and bracings associated with masonry walls, and periodic evaluation of ground water chemistry and opportunistic inspections for the condition of below grade concrete. Quantitative results (measurements) and qualitative information from periodic inspections are trended with sufficient detail, such as photographs and surveys for the type, severity, extent, and progression of degradation, to ensure that corrective actions can be taken prior to a loss of intended function. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program includes personnel qualifications and quantitative evaluation criteria of ACI 349.3R.

16.2.2.35. Inspection of Water-Control Structures Associated with Nuclear Power Plants

The PBN Water-Control Structures AMP is an existing AMP that is currently implemented as part of the PBN Structures Monitoring Program. The PBN Water-Control Structures AMP was evaluated as a portion of the PBN Structures Monitoring AMP in the initial LRA. The PBN Water-Control Structures AMP is evaluated separately in the SLRA and it is compared to the NUREG-2191, Section XI.S7 program. This condition monitoring AMP addresses age-related deterioration, degradation due to environmental conditions, and the effects of natural phenomena that may affect water-control structures.

The PBN Water-Control Structures AMP consists of inspection and surveillance of raw-water control structures. The structures within the scope of the PBN Water-Control Structures AMP include the forebay and the circulating water pumphouse (CWPH) building. The program also includes structural steel and structural bolting associated with water-control structures. Parameters monitored are in accordance with Section C.2 of RG 1.127 and quantitative measurements are recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. Inspections occur at least once every 5 years. Evaluation of ground water chemistry is performed under the scope of the PBN Structures Monitoring AMP. The periodic lake water chemical analyses will continue to be performed at least once every 5 years to assure that the below-grade/lake-water environment remains chemically non-aggressive.

16.2.2.36. Protective Coating Monitoring and Maintenance

The PBN Protective Coating Monitoring and Maintenance AMP is an existing AMP that provides reasonable assurance that monitoring and maintenance of Service Level 1 coatings are implemented in accordance with Position C4 of Regulatory Guide 1.54, Revision 3. The program consists of guidance for selection, application, inspection, and maintenance of protective coatings. The AMP uses the aging management detection methods, inspector qualifications, inspection frequency, monitoring and trending, and acceptance criteria defined in ASTM D 5163-08, “Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants”. The program addresses coatings applied to steel and concrete surfaces inside containment. Degraded coatings in the containment are assessed periodically to ensure post-accident operability of the Emergency Core Cooling System (ECCS).

16.2.2.37. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, previously part of the Cable Conditioning Monitoring Program, is an existing AMP. This AMP applies to accessible non-EQ electrical cable and connection electrical insulation material within the scope of SLR subjected to an adverse localized environment (e.g., heat, radiation, or moisture). Adverse localized environments are identified through the use of an integrated approach, which includes, but is not limited to, a review of relevant site-specific and industry OE, field walkdown data, etc. Accessible non-EQ insulated cable and connections within the scope of SLR installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies indicating signs of reduced electrical insulation resistance. The first inspection for SLR is to be completed no later than six months prior to entering the SPEO. Recurring inspections are to be performed at least once every 10 years thereafter.

If visual inspections identify cable jacket and connection insulation surface anomalies, then testing may be performed. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. A sample population of cable and connection insulation is utilized if testing is performed. If testing is deemed necessary, a sample of 20 percent of each cable and connection type with a maximum sample size of 25 is tested. When acceptance criteria are not met, a determination is made as to whether the surveillance, inspection, or tests, including frequency intervals, need to be modified.

Electrical insulation material for cables and connectors previously identified and dispositioned during the first period of extended operation as subjected to an adverse localized environment are evaluated for cumulative aging effects during the SPEO.

16.2.2.38. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

The PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP, previously part of the Cable Conditioning Monitoring Program, is an existing AMP. This AMP manages the aging effects of the applicable cables and connections in the following systems or sub-systems:

- Nuclear Instrumentation: Excore Source, Intermediate, and Power Range Channels

This purpose of this AMP is to provide reasonable assurance that non-EQ cables and connections used in high voltage, low-level current signal applications that are sensitive to reduction in electrical insulation resistance will perform their intended function consistent with the CLB throughout the SPEO.

In this AMP, either of two methods can be used to identify the existence of electrical insulation aging effects for cables and connections. In the first method, calibration results or findings of surveillance testing programs are evaluated to identify the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. In this method, the first reviews are completed no later than 6 months prior to the SPEO and at least once every 10 years thereafter.

In the second method, direct testing of the cable system is performed. Cable system testing is conducted when the calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results or findings of surveillance testing programs. In the second method, the test frequency of the cable system is determined based on engineering evaluation, but the first tests are completed no later than 6 months prior to the SPEO and at least once every 10 years thereafter.

16.2.2.39. Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, previously part of the Cable Conditioning Monitoring Program, is an existing AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of inaccessible medium-voltage (M-V) power cables (operating voltages of 2 kV to 35 kV) that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO. This AMP applies to inaccessible (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct-buried installations) non-EQ medium-voltage power cables within the scope of SLR exposed to wetting or submergence (i.e., significant moisture). Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long-term wetting or submergence over a continuous period), which if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that occurs for a limited time as drainage from either automatic or passive drains is not considered significant moisture for this AMP.

In-scope inaccessible M-V power cables exposed to significant moisture are tested to determine the condition of the electrical insulation. One or more tests may be required based on cable application, construction, and electrical insulation material to determine the age degradation of the cable. The first tests for license renewal are to be completed no later than 6 months prior to the SPEO with subsequent tests performed at least once every six years thereafter. Submarine or other cables designed for continuous wetting or submergence are also included in this AMP as a one-time inspection and test with additional periodic tests and inspections determined by the one-time test/inspection results as well as industry and plant-specific OE.

This AMP includes periodic actions to prevent inaccessible M-V power cables from being exposed to significant moisture. Periodic actions to mitigate inaccessible M-V power cable exposure to significant moisture include inspection for water accumulation in cable manholes and conduits, and removing water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the SPEO. Inspection frequencies are adjusted based on inspection results, including site-specific OE, but with a minimum inspection frequency of at least once annually. Inspections are also performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. The periodic inspection includes documentation of the effectiveness of either automatic or passive drainage systems, or manual pumping of manholes or vaults, in preventing inaccessible M-V power cable exposure to significant moisture.

16.2.2.40. Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PBN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of inaccessible instrumentation and control (I&C) cables that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO. This AMP applies to inaccessible (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) I&C cables within the scope of SLR exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long-term wetting or submergence over a continuous period), which if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

This AMP includes periodic actions to prevent inaccessible I&C cables from being exposed to significant moisture. Periodic actions taken to mitigate inaccessible I&C cable exposure to significant moisture include inspection for water accumulation in cable manholes / vaults and conduit ends, and removing or draining water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the SPEO. Inspections are also performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. The periodic inspection includes documentation of the effectiveness of either automatic or passive drainage systems, or manual pumping of manholes or vaults, in preventing inaccessible I&C cable exposure to significant moisture.

In addition to inspecting for water accumulation, I&C cables accessible from manholes, vaults, or other underground raceways are periodically visually inspected for jacket surface abnormalities, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The cable insulation visual inspection portion of the AMP uses the cable jacket material as representative of the aging effects experienced by the I&C cable electrical insulation. Inspection frequencies are adjusted based on inspection results, including plant-specific OE. The visual inspection of inaccessible I&C cables occurs at least once every six years and may be coordinated with the periodic inspection for water accumulation. Inaccessible (e.g., underground) I&C cables found to be exposed to significant moisture are evaluated to determine whether testing is required. If testing is warranted, initial cable testing is performed once on a sample population to determine the condition of the electrical insulation. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. One or more tests may be required due to cable type, application, and electrical insulation to determine the age degradation of the cable. Inaccessible and underground I&C cables designed for continuous wetting or submergence are also included in this AMP as a one-time inspection and test. The need for additional tests and inspections is determined by the test/inspection results, as well as industry and plant-specific OE.

Testing of installed inservice inaccessible (e.g., underground) I&C cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage power cables or low-voltage power cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible I&C cables when testing is required in this AMP.

16.2.2.41. Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PBN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of inaccessible (e.g., underground) low-voltage ac and dc power cables (i.e., typical operating voltage of less than 1,000 V, but no greater than 2 kV) that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO. This AMP applies to inaccessible (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) low-voltage power cables, including those designed for continuous wetting or submergence, within the scope of SLR exposed to significant moisture. In-scope inaccessible low-voltage power cable splices subjected to wetting or submergence are included within the scope of this program. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long-term wetting or submergence over a continuous period), which if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

This AMP includes periodic actions to prevent inaccessible low-voltage power cables from being exposed to significant moisture. Periodic actions taken to mitigate inaccessible low-voltage power cable exposure to significant moisture include inspection for water accumulation in cable manholes and conduits, and removing or draining water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the SPEO. Inspections are also performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. The periodic inspection includes documentation of the effectiveness of either automatic or passive drainage systems, or manual pumping of manholes or vaults, in preventing inaccessible low voltage power cable exposure to significant moisture.

In addition to inspecting for water accumulation, low-voltage power cables accessible from manholes, vaults, or other underground raceways are periodically visually inspected for jacket surface abnormalities, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The cable insulation visual inspection portion of the AMP uses the cable jacket material as representative of the aging effects experienced by the low-voltage power cable electrical insulation. Inspection frequencies are adjusted based on inspection results, including plant-specific OE. The visual inspection of inaccessible low-voltage power cables occurs at least once every six years and may be coordinated with the periodic inspection for water accumulation. Inaccessible (e.g., underground) low-voltage power cables found to be exposed to significant moisture are evaluated to determine whether testing is required. If testing is warranted, initial cable testing is performed once on a sample population to determine the condition of the electrical insulation. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. One or more tests may be required due to cable type, application, and electrical insulation material to determine the age degradation of the cable insulation. Inaccessible and underground low-voltage power cables designed for continuous wetting or submergence are also included in this AMP as a one-time inspection and test. The need for additional tests and inspections is determined by the test/inspection results, as well as industry and plant-specific OE.

Testing of installed inservice inaccessible (e.g., underground) low-voltage power cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage power cables or I&C cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible low-voltage power cables when testing is required in this AMP.

16.2.2.42. Metal Enclosed Bus

The PBN Metal Enclosed Bus (MEB) AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the effects of aging on metal enclosed bus within the scope of SLR are adequately managed so that component intended function(s) are maintained consistent with the CLB for the SPEO.

This AMP manages the age-related degradation effects for electrical bus bar bolted connections, bus bar electrical insulation, bus bar insulating supports, bus enclosure assemblies (internal and external), and elastomer components (e.g., gaskets, boots, and sealants). This program does not manage the aging effects on external MEB surfaces or structural supports, which are managed under the PBN Structures Monitoring AMP. The first inspection for SLR will be completed prior to the SPEO and every 10 years thereafter.

MEB bolted bus connections are tested on a sampling basis to ensure the connections are not experiencing increased resistance due to loosening of bolted bus duct connections caused by repeated thermal cycling of connected loads by using thermography or by measuring connection resistance using a micro ohmmeter. A sample of 20 percent with a maximum sample of 25 constitutes a representative bolted bus connection sample size. If thermography is used, it will be documented that thermography is effective in identifying MEB increased resistance of connection (e.g., infrared viewing windows installed, or demonstrated test equipment capability). In addition to thermography or resistance measurement, bolted connections not covered with heat shrink tape or boots are visually inspected for increased resistance of connection (e.g., loose or corroded bolted connections and hardware including cracked or split washers). The first resistance testing of the internal bus connections will be completed prior to the SPEO, and every 10 years thereafter.

As an alternative to thermography or measuring connection resistance of bolted connections, for accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., PBN may use visual inspection of insulation material to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. If the alternative visual inspection is used to check MEB bolted connections, the first inspection will be completed prior to the SPEO and every 5 years thereafter.

16.2.2.43. Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PBN Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of the metallic parts of electrical cable connections that are not subject to the EQ requirements of Title 10 of the Code of Federal Regulations (10 CFR) 50.49 and susceptible to age-related degradation resulting in increased resistance are maintained consistent with the CLB through the SPEO.

This AMP is a one-time AMP that manages the aging mechanisms and effects that result in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation of the metallic portions of electrical cable connections within the scope of SLR.

This AMP focuses on the metallic parts of the electrical cable connections. One-time testing, on a sample basis, is performed to confirm the absence of age-related degradation of cable connections resulting in increased resistance of the connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation. Wiring connections internal to an active assembly are considered part of the active assembly and, therefore, are not within the scope of this AMP. This program does not apply to high voltage (> 35 kV) switchyard connections. Cable connections covered under the EQ program are not included in the scope of this program.

A representative sample of cable connections within the scope of SLR are tested on a one-time test basis to confirm the absence of age-related degradation of the cable connection. Initial one-time test findings will document unacceptable conditions or degradation identified and whether they were determined to be age-related thereby requiring subsequent testing on a 10-year basis. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. One-time testing provides additional confirmation to support industry OE that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective. Depending on the findings of the one-time test, subsequent testing may have to be performed within 10 years of the initial testing. The following factors are considered for sampling: voltage level (medium and low-voltage), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.). Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. The first tests for SLR are to be completed prior to the SPEO.

As an alternative to measurement testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., a visual inspection of insulation materials may be used to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination. When this alternative visual inspection is used to check cable connections, the first inspection is completed prior to the SPEO and at least every 5 years thereafter. The basis for performing only a periodic visual inspection, if selected, will be documented.

16.2.2.44. <u>High-Voltage Insulators</u>

The PBN High-Voltage Insulators AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of high-voltage insulators within the scope of SLR are maintained consistent with the CLB through the SPEO. The High-Voltage Insulator AMP was developed specifically to age manage high-voltage insulators susceptible to aging degradation due to local environmental conditions.

This AMP manages reduced insulation resistance of high-voltage insulator surfaces due to contamination from various airborne contaminates such as dust, salt, fog or industrial effluent. The metallic portions of the high-voltage insulators are subject to loss of material from either mechanical wear caused by oscillating movement of the insulators due to wind, and / or surface corrosion from substantial airborne contamination such as salt.

The program includes the inspection of the high-voltage insulators within the scope of this program to identify degradation of high-voltage insulator sub-component parts, namely; insulation and metallic elements. Visual inspection is performed to provide reasonable assurance that the applicable aging effects are identified and high-voltage insulator age degradation is managed. Insulation materials used in high-voltage insulators may degrade more rapidly than expected when installed in an environment conducive to accelerated aging. The insulation and metallic elements of high-voltage insulators are made of porcelain, cement, malleable iron, aluminum, and galvanized steel. Significant loss of metallic material can occur due to mechanical wear caused by oscillating movement of insulators due to wind. Surface corrosion in metallic parts may appear due to airborne contamination or where galvanized or other protective coatings are worn. With substantial airborne contamination such as salt, surface corrosion in metallic parts may become significant such that the insulator no longer will support the conductor. Various airborne contaminates such as dust, salt, fog or industrial effluent can contaminate the insulator surface leading to reduced insulation resistance. Excessive surface contaminants or loss of material can lead to insulator flashover and failure. Reduced insulation resistance can be caused by the presence of insulator surface contamination. Visual inspections may be supplemented with infrared thermography inspections to detect high-voltage insulator reduced insulation resistance.

The high-voltage insulators within the scope of this program are to be visually inspected at a frequency based on plant-specific OE. The first inspections for SLR are to be completed prior to the SPEO.

16.3. Time-Limited Aging Analysis

With respect to plant TLAAs, 10 CFR 54.21(c) states the following:

> *(c) An evaluation of time-limited aging analyses.*
>
> *(1) A list of time-limited aging analyses, as defined in § 54.3, must be provided. The applicant shall demonstrate that--*
>
> *(i) The analyses remain valid for the period of extended operation;*
> *(ii) The analyses have been projected to the end of the period of extended operation; or*
> *(iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.*

This section discusses the evaluation results for each of the site-specific TLAA performed for SLR. The evaluations have demonstrated that the analyses remain valid for the SPEO; that the analyses have been projected to the end of the SPEO; or that the effects of aging on the intended function(s) will be adequately managed for the SPEO. The TLAAs, as defined in 10 CFR 54.3, are listed in Section 16.3.2 through, and including, Section 16.3.7.6 and are evaluated per the requirements of 10 CFR 54.21(c).

16.3.1. Identification of Time-Limited Aging Analyses Exemptions

10 CFR 54.21(c)(2) states the following with respect to TLAA exemptions:

> *A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.*

A search of docketed licensing correspondence, the operating license, and the

UFSAR was performed to identify the active exemptions currently in effect pursuant to 10 CFR 50.12. These exemptions were then reviewed to determine whether the exemption was based on a TLAA. No 10 CFR 50.12 exemptions involving a TLAA, as defined in 10 CFR 54.3, were identified for PBN Units 1 and 2. This addresses the 10 CFR 54.21(c)(2) exemptions list requirement.

16.3.2. Reactor Vessel Neutron Embrittlement

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, pressure-temperature (P-T) limits, and materials surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H. The PBN Reactor Vessel Material Surveillance AMP is described in Section 16.2.2.19.

The ferritic materials of the reactor vessel are subject to embrittlement due to high energy (E > 1.0 MeV) neutron exposure. Neutron embrittlement means the material has lower toughness (i.e., will absorb less strain energy during a crack or rupture), thus allowing a crack to propagate more easily under thermal and pressure loading. Neutron embrittlement analyses are used to account for the reduction in fracture toughness associated with the cumulative neutron fluence (total number of neutrons that intersect a square centimeter of component area during the life of the plant). This group of TLAAs concerns the effect of neutron embrittlement on the belt-line regions of the PBN Units 1 and 2 reactor vessels, and how this mechanism affects analyses that provide operating limits or address regulatory requirements.

Neutron fluence is used to calculate parameters for embrittlement analyses that are part of the CLB and support safety determinations, and since these analyses are calculated based on plant life, they have been identified as TLAAs, as defined in 10 CFR 54.21(c). Therefore, the following TLAAs were evaluated for the increased neutron fluence associated with 80 years of operations:

- Neutron fluence projections (Section 16.3.2.1)
- Pressurized thermal shock (PTS) (Section 16.3.2.2)
- Upper-shelf energy (USE) (Section 16.3.2.3)
- Adjusted reference temperature (Section 16.3.2.4)
- Pressure-temperature limits and low temperature overpressure protection (LTOP) setpoints (Section 16.3.2.5)

16.3.2.1. Neutron Fluence Projections

Neutron fluence is the term used to represent the cumulative number of neutrons per square centimeter that contact the reactor pressure vessel (RPV) shell. The fluence projections that quantify the number of neutrons that contact these surfaces have been used as inputs to the neutron embrittlement analyses that evaluate the reduction of fracture toughness aging effect

The effective full power year (EFPY) projections through the end of the SPEO for a unit is the sum of the accumulated EFPY and the projected future EFPY. EFPY at the end of 60 years of operation was calculated to be 53 EFPY. The projected 80-year EFPY for both Units 1 and 2 is 72 EFPY.

Updated fluence projections were developed for 80 years of plant operation, based upon 72 EFPY for use as inputs to updated neutron embrittlement analyses for the SPEO. The 72 EFPY fluence projections were developed using methodologies that follow the guidance of NRC Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence” and is consistent with the NRC approved methodology described in WCAP-18124-NP-A. The 72 EFPY fluence projections have been determined for reactor vessel beltline and extended beltline materials, which include all reactor vessel forgings, plate material, and welds that are predicted to be exposed to 1.0 x 10^{17} neutrons/cm^2 (n/cm^2) or more during 80 years of operation. The neutron fluence projections have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

The PBN Neutron Fluence Monitoring AMP (Section 16.2.1.2) and the PBN Reactor Vessel Material Surveillance AMP (Section 16.2.2.19) ensure the continued validity and adequacy of projected neutron fluence analyses and related neutron fluence-based TLAAs as described in Section 16.2.1.2 and Section 16.2.2.19, respectively.

16.3.2.2. Pressurized Thermal Shock

A limiting condition on RPV integrity known as Pressurized Thermal Shock (PTS) may occur during a severe system transient such as a small-break loss-of-coolant accident (LOCA) or steam line break. Such transients may challenge the integrity of the RPV under the following conditions: severe overcooling of the inside surface of the vessel wall followed by repressurization, significant degradation of vessel material toughness caused by radiation embrittlement, and the presence of a critical-size defect anywhere within the vessel wall.

10 CFR 50.61(c) provides two methods for determining RT_{PTS}. These methods are also described as Positions 1 and 2 in Regulatory Guide 1.99. Position 1 applies for material without credible surveillance data available and Position 2 is used for material with two or more credible surveillance data sets available. The RT_{PTS} values are calculated for both Positions 1 and 2 by following the guidance in Regulatory Guide 1.99 (Sections 1.1 and 2.1, respectively), using the copper and nickel content of the Units 1 and 2 beltline materials, and SPEO fluence projections.

10 CFR 50.61(b)(2) establishes screening criteria for RT_{PTS} as 270°F for plates, forgings, and longitudinal welds and 300°F for circumferential welds. All of the beltline materials in the Unit 1 and Unit 2 RVs are below the RT_{PTS} screening criteria values of 270°F for base metal and longitudinal welds, and 300°F for circumferentially oriented welds through the SPEO (72 EFPY).

The limiting RT_{PTS} value for the Unit 1 base metal or longitudinal weld at 72 EFPY is 248.9°F, which corresponds to the intermediate shell longitudinal weld. The limiting RT_{PTS} value for the Unit 1 circumferentially oriented welds at 72 EFPY is 254.0°F, which corresponds to the intermediate to lower shell circumferential weld.

The limiting RT_{PTS} value for the Unit 2 base metal at 72 EFPY is 159.8°F, which corresponds to the intermediate shell forging. The limiting RT_{PTS} value for the Unit 2 circumferentially oriented welds at 72 EFPY is 292.6°F, which corresponds to the intermediate to lower shell circumferential weld.

Therefore, the PTS TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

16.3.2.3. Upper-Shelf Energy

Appendix G of 10 CFR Part 50, Paragraph IV.A.1.a, states that reactor vessel beltline materials must have Charpy USE of no less than 75 ft-lb initially, and must maintain Charpy USE throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

For SLR, the USE values for the beltline and extended beltline materials were determined using methods consistent with Regulatory Guide 1.99, Revision 2. Two methods may be used to predict the decrease in USE with irradiation, depending on the availability of credible surveillance capsule data as defined in Regulatory Guide 1.99, Revision 2. For vessel beltline materials that are not in the surveillance program or for locations with non-credible data, the Charpy USE is assumed to decrease as a function of fluence and copper content, as indicated in Regulatory Guide 1.99, Revision 2 (Position 1.2). When two or more credible surveillance data sets are available from the reactor, they may be used to determine the Charpy USE of the surveillance material. The surveillance data are then used in conjunction with the regulatory guide to predict the change in USE of the reactor vessel material due to irradiation (Position 2.2).

The 72 EFPY Regulatory Guide 1.99, Revision 2 (Position 1.2) USE values of the vessel materials can be predicted using the corresponding 1/4T fluence projection, the copper content of the materials, and Figure 2 in Regulatory Guide 1.99, Revision 2. The predicted Position 2.2 USE values are determined for the reactor vessel materials that are contained in the surveillance program by using the plant surveillance data along with the corresponding 1/4T fluence projection. The projected USE values were calculated to determine if the PBN Units 1 and 2 beltline and extended beltline materials remain above the 50 ft-lb limit at 72 EFPY.

All PBN Unit 1 reactor vessel beltline and extended beltline materials maintain a USE value greater than 50 ft-lbs through 72 EFPY except for nozzle belt forging-to-intermediate shell plate circumferential weld (SA-1426), intermediate shell axial weld (SA-812/SA-775), intermediate shell-to-lower shell circumferential weld (SA-1101), lower shell axial weld (SA-847), and intermediate shell plate (A9811-1).

All PBN Unit 2 reactor vessel beltline and extended beltline materials maintain a USE value greater than 50 ft-lbs through 72 EFPY except for the intermediate shell forging-to-lower shell forging circumferential weld (SA-1484).

For the PBN Units 1 and 2 reactor vessel Linde 80 weld materials that do not maintain a USE value above 50 ft-lbs through 72 EFPY, an equivalent margins analysis (EMA) was performed to demonstrate that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code. The 72 EFPY PBN EMA for Linde 80 welds are reported in Framatome topical report supplement 3 to BAW-2192P/NP and supplement 2 to BAW-2178P/NP.

Equivalent Margins Analysis (EMA)-Linde 80 Welds

The analytical procedure used for the 72 EFPY equivalent margins analyses of Linde 80 welds for PBN Units 1 and 2 is in accordance with ASME Section XI, Appendix K, 2017 Edition, with selection of design transients based on the guidance in Regulatory Guide 1.161. Results of the EMA are summarized below.

Levels A & B Service Loads

Reactor Vessel Shell Welds

- The limiting RV Linde 80 weld is PBN Unit 1 axial weld (SA-812), which bounds all Unit 1 and Unit 2 Linde 80 welds. With factors of safety of 1.15 on pressure and 1.0 on thermal and mechanical loading on axial weld (SA-812), the applied J-integral (J_1) is less than the J-integral of the material at a ductile flaw extension of 0.10 in. ($J_{0.1}$). The ratio J0.1/J1 is greater than the required value of 1.0.

- With a factor of safety of 1.25 on pressure and 1.0 on thermal and mechanical loading on axial weld (SA-812), flaw extensions are ductile and stable since the slope of the applied J-integral curve is less than the slope of the lower bound J-R curve at the point where the two curves intersect.

Levels C & D Service Loads

Reactor Vessel Shell Welds

- With a factor of safety of 1.0 on loading, the applied J-integral (J_1) for the limiting reactor vessel weld (SA-812) is less than the lower bound J-integral of the material at a ductile flaw extension of 0.10 inch ($J_{0.1}$) with a ratio $J_{0.1}/J_1$ is greater than the required value of 1.0.

- With a factor of safety of 1.0 on loading, flaw extensions are ductile and stable for the limiting reactor vessel weld (SA-812) since the slope of the applied J-integral curve is less than the slopes of both the lower bound and mean J-R curves at the points of intersection.

- For reactor vessel weld (SA-812) flaw growth is stable at much less than 75 percent of the vessel wall thickness. Also, the remaining ligament is sufficient to preclude tensile instability by a large margin.

<u>B&WOG J-R Model 6B</u>

B&WOG J-R Model 6B is shown to be applicable to PBN Units 1 and 2. Specifically, the PBN Linde 80 material properties (i.e., copper content) and 80-year projected fluence at the 1/4T location (update for t/10 location later when BAW-2192, Supplement 3, Appendix A is completed) are within the range of explanatory variables used to develop B&WOG Model 6B, which is qualified for subsequent license renewal. Therefore, use of B&WOG Model 6B mean and lower bound J-integral resistance values at crack extensions of 0.1 inches are appropriate for the Linde 80 weld EMA's for PBN Units 1 and 2

Equivalent Margins Analysis (EMA)-Unit 1 Intermediate Shell Plate A9811-1

The analytical procedure used for the 72 EFPY equivalent margins analysis of PBN Unit 1 IS plate A9811-1 is in accordance with ASME Section XI, Appendix K, 2017 Edition, with selection of design transients based on the guidance in Regulatory Guide 1.161. Results of the EMA are summarized below.

Levels A & B Service Loads

- The applied J-integral values for the assumed 1/4-thickness inside-surface circumferential and axial flaws in the IS plate (A9811-1) with a structural factor of 1.15 on pressure loading is within the material fracture toughness J-resistance at 0.1-inch crack extension. The ratio $J_{0.1}/J_1$ is greater than the required value of 1.0 for both the axial and circumferential postulated flaws. The limiting flaw is an axial flaw at the top of IS plate A9811-1, utilizing the CVN values at the top and bottom of the plate in the strong direction, to index the Specimen V-50-101, 6T, J-R data.

- With a structural factor of 1.25 on pressure and 1.0 on thermal loading, flaw extensions are ductile and stable since the slope of the applied J-integral curve is less than the slope of the lower bound J-R curve for crack extensions less than or equal to 0.10-inches.

Levels C & D Service Loads

- With a structural factor of 1.0 on loading, the applied J-integral (J_1) for the IS plate (A9811-1) postulated axial and circumferential and flaws are less than the lower bound J-integral of the material at a ductile flaw extension of 0.10 inch ($J_{0.1}$) with a ratio $J_{0.1}/J_1$ is greater than the required value of 1.0.

- With a structural factor of 1.0 on loading, flaw extensions are ductile and stable for the IS plate (A9811-1) postulated circumferential and axial flaws since the slopes of the applied J-integral curves are less than the slopes of the lower bound J-R curves for crack extensions less than or equal to 0.10-inches.

- For the postulated circumferential and axial flaws in IS plate (A9811-1), the flaw growth is stable at much less than 75 percent of the vessel wall thickness. Also, the remaining ligament is sufficient to preclude tensile instability by a large margin.

The margins ($J_{0.1}/J_1$) at 72 EFPY for PBN Unit 1 IS plate A9811-1 for service loads A-D are approximately similar to that of PBN Unit 1 Linde 80 Weld SA-812.

Therefore, the USE analyses have been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

16.3.2.4. <u>Adjusted Reference Temperature</u>

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the beltline P-T limit curves to account for irradiation effects. Regulatory

Guide 1.99, Revision 2, provides the methodology for determining the ART of the limiting material. The initial nil ductility reference temperature, RT_{NDT}, is the temperature at which a non-irradiated metal (ferritic steel) changes in fracture characteristics from ductile to brittle behavior. RT_{NDT} is evaluated according to the procedures in the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Paragraph NB-2331. Neutron embrittlement increases the RT_{NDT} beyond its initial value.

10 CFR Part 50, Appendix G, defines the fracture toughness requirements for the life of the vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lb index temperatures from the average Charpy curves measured before and after irradiation. This increase (ΔRT_{NDT}) means that higher temperatures are required for the material to continue to act in a ductile manner.

The 72 EFPY fluence values were used to compute ART values for the PBN RPV beltline and extended beltline materials in accordance with NRC RG 1.99, Revision 2, requirements. Therefore, the ART TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

16.3.2.5. Pressure-Temperature Limits and Low Temperature Overpressure Protection (LTOP) Setpoints

10 CFR Part 50 Appendix G requires that the RPV be maintained within established pressure-temperature (P-T) limits, including heatup and cooldown operations. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the RPV is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated RPV fluence effect on fracture toughness.

The current PBN Units 1 and 2 heatup and cooldown curves were calculated using the most limiting value of RT_{NDT} corresponding to the limiting material in the beltline region of the reactor vessel for 50 EFPY based on EPU fluences.

In accordance with NUREG-2192, Section 4.2.2.1.4, the P-T limits for the SPEO need not be submitted as part of the SLRA since the P-T limits are required to be updated through the 10 CFR 50.90 licensing process when necessary for P-T limits that are located in the Technical Specifications. The 10 CFR 50.90 process will ensure that the P-T limits for the SPEO will be updated prior to expiration of the P-T limits for the current period of operation.

Additionally, PBN Technical Specifications specify the power operated relief valve (PORV) lift settings to mitigate the consequences of LTOP events. Each time the P-T limit curves are revised, the LTOP PORV setpoints must be reevaluated. Therefore, LTOP protection limits are considered part of the calculation of P-T curves.

The P-T limit curves and LTOP PORV setpoints will be updated (if required) and a Technical Specification change request will be submitted for approval prior to exceeding the current 50 EFPY limits. The PBN Reactor Vessel Material Surveillance AMP (Section 16.2.2.19) will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval prior to exceeding the current terms of applicability for PBN Units 1 and 2.

Therefore, the P-T limits and LTOP protection TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

16.3.3. Metal Fatigue

Fatigue is an age-related degradation mechanism caused by cyclic stressing of a component by either mechanical or thermal stresses. The thermal and mechanical fatigue analyses of plant mechanical components have been identified as TLAAs for PBN. Specific components have been designed considering transient cycle assumptions, as listed in vendor specifications and the PBN UFSAR. Fatigue analyses are considered TLAAs for Class 1 and non-Class 1 mechanical components requiring evaluation for the SPEO in accordance with 10 CFR 54.21(c).

The following metal fatigue evaluations are documented in the following sections:

- Metal fatigue of Class 1 Components (Section 16.3.3.1)
- ASME Code, Section III, Class 1 Component Fatigue Waivers (Section 16.3.3.2)
- Metal fatigue of Non-Class 1 Components (Section 16.3.3.3)
- Environmentally-assisted Fatigue (Section 16.3.3.4)

16.3.3.1. Metal Fatigue of ASME Section III, Class 1 Components

Section III of the ASME Code requires a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded. The ASME Code Section III fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients described in the design specifications. The intent of the design basis transient definitions is to bound a wide range of possible events with varying ranges of severity in temperature, pressure, and flow. The fatigue analyses were required to demonstrate that the cumulative usage factor (CUF) will not exceed the design allowable limit of 1.0 when the equipment is exposed to all of the postulated transients. Since the calculation of fatigue usage factors is part of the CLB and is used to support safety determinations, and since the number of occurrences of each transient type was based upon 60-year assumptions, these Class 1 fatigue analyses have been identified as TLAAs requiring evaluation for the SPEO.

The following ASME Code, Section III components were assessed for impact on fatigue:

- Reactor vessels
- Control rod drive mechanism
- Steam generators
- Reactor coolant pumps
- Pressurizers
- Reactor vessel internals

- Pressurizer surge lines
- Pressurizer spray piping

The fatigue analysis for the pressurizer piping spray piping has been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

The 40-year design cycles (CLB cycles) for the remaining Class 1 components were determined to bound 80 years of plant operations. Therefore, the fatigue analyses remain valid for the SPEO. In order to ensure the design cycles remain bounding in the fatigue analyses, the PBN Fatigue Monitoring AMP (Section 16.2.1.1) will track cycles for significant fatigue transients listed in the UFSAR, Table 4.1-8 and ensure corrective action is taken prior to potentially exceeding fatigue design limits. Therefore, the effects of fatigue on the intended function(s) of ASME Code, Section III components will be adequately managed by the PBN Fatigue Monitoring AMP (Section 16.2.1.1) for the SPEO operation in accordance with 10 CFR 54.21(c)(1)(iii).

16.3.3.2. <u>ASME Code, Section III, Class 1 Component Fatigue Waivers</u>

A detailed fatigue evaluation is not required if components conform to the waiver of fatigue requirements of ASME Code, Section III. Fatigue waivers that consider transient cycles that occur over the life of the plant constitute TLAAs. The following equipment have sub-components that conform to the waiver of fatigue requirements in ASME Code, Section III:

- Steam generators
  - Shop installed welded tube plugs
  - Ribbed mechanical tube plugs
  - Tube wall undercut

The PBN extended power uprate (EPU) project indicates that the three steam generator sub-components listed above conform to the waiver of fatigue requirements in ASME Section III. The six fatigue exemption conditions in N-415.1 of ASME Section III were evaluated for these sub-components in lieu of an explicit calculation of the usage factor. The fatigue exemption evaluations for these sub-components considers the normal and upset design transients.

The 40-year design cycles (CLB cycles) were determined to bound 80 years of plant operations. Therefore, the fatigue analyses remain valid for the SPEO. In order to ensure the design cycles remain bounding in the fatigue analyses, the Fatigue Monitoring AMP (Section 16.2.1.1) will track cycles for significant fatigue transients listed in the UFSAR, Table 4.1-8 and ensure corrective action is taken prior to potentially exceeding fatigue design limits. Therefore, the fatigue waivers for Class 1 components remain valid for the SPEO. The effects of fatigue on these components will be adequately managed by the PBN Fatigue Monitoring AMP (Section 16.2.1.1) for the SPEO operation in accordance with 10 CFR 54.21(c)(1)(iii).

16.3.3.3. <u>Metal Fatigue of Non-Class 1 Components</u>

The PBN reactor coolant system primary loop piping and balance-of-plant piping systems within the scope of subsequent license renewal are designed to the requirements of ANSI B31.1, Power Piping. The exceptions are the PBN Units 1 and 2 pressurizer surge lines and pressurizer spray piping which have been analyzed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III.

Piping and components designed in accordance with ANSI B31.1 design rules are not required to have an explicit analysis of cumulative fatigue usage, but cyclic loading is considered in a simplified manner in the design process. The code first requires prediction of the overall number of thermal and pressure cycles expected during the lifetime of these components. Then a stress range reduction factor is determined for that number of cycles using a table from the applicable design code. If the total number of cycles is 7,000 or less, the stress range reduction factor is 1.0, which when applied, would not reduce the allowable stress value.

A review of the ANSI B31.1 piping within the scope of SLR was performed in order to identify those systems that operate at elevated temperature and to establish their cyclic operating practices. Under current plant operating practices, piping systems within the scope of SLR are only occasionally subject to cyclic operation. From EPRI TR-104534, Volume 2, Section 4, piping systems subject to thermal fatigue due to temperature cycling are described as follows:

> *For initial screening, systems in which the fluid temperature can vary more than 200°F in austenitic steel components and more than 150°F in carbon and low alloy steel components are potentially of concern for fatigue due to thermal transients. Thus, carbon steel systems or portions of systems with operating temperatures less than 220°F and stainless steel systems or portions of systems with operating temperatures less than 270°F may generally be excluded from such concerns, since room temperature represents a practical minimum exposure temperature for most plant systems.*

Conservatively, based on this assessment, any system or portions of systems with operating temperatures less than 220°F were excluded from further consideration. Any B31.1 piping system or portions of systems with operating temperatures above 220°F are conservatively evaluated for fatigue. Once a system is established to operate at a temperature above 220°F, system operating characteristics are established, and a determination is made as to whether the system is expected to exceed 7000 full temperature cycles in 80 years of operation. In order to exceed 7000 cycles a system would be required to heatup and cooldown approximately once every four days. For the systems that are subjected to elevated temperatures above the fatigue threshold, an evaluation was performed to determine a conservative number of projected full temperature cycles for 80 years of plant operation. These projections conclude that 7000 thermal cycles will not be exceeded for 80 years of operation. Therefore, the ANSI B31.1 allowable stress calculations remain valid for the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

16.3.3.4. Environmentally-Assisted Fatigue

As outlined in Section X.M1 of NUREG-2191 and Section 4.3 of NUREG-2192, the effects of the reactor water environment on CUF must be examined for a set of sample critical components for the plant. This sample set includes the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR-6260. These additional limiting locations are identified through an environmental fatigue screening evaluation. The environmentally-assisted fatigue (EAF) screening evaluation reviewed the CLB fatigue evaluations for all ASME Code, Section III reactor coolant pressure boundary components and ANSI B31.1 piping, including the NUREG/CR-6260 locations, to determine the lead indicator (also referred to as sentinel) locations for EAF.

To support subsequent license renewal, calculations were prepared to document the evaluations of EAF for ASME Code, Section III and ANSI B31.1 RCS pressure boundary components and piping and determine fatigue-sensitive locations for comparison and ranking. These evaluations are for subsequent license renewal purposes only and do not amend the existing design reports.

The EAF evaluations for ASME Section III components were performed using the guidelines in NRC Regulatory Guide 1.207 and the F_{en} equations in Revision 1 of NUREG/CR-6909. The goal of these EAF evaluations was to calculate a CUF_{en} below 1.0 through typical linear elastic fatigue analysis techniques. Conservatisms in the stress and fatigue analyses in the AORs were identified and removed, if possible, in the CUF calculations.

Piping analyses previously performed for 60-year license renewal (LR) were used as inputs to the SLR EAF calculations. These calculations provide the transient loads, component materials, evaluated locations, and fatigue analysis results used as input to the SLR EAF calculation. The following ANSIB 31.1 piping sentinel locations for SLR are:

- Hot leg surge nozzle
- Charging nozzle
- Accumulator safety injection nozzle
- RHR tee
- Pressurizer spray piping

The results of the EAF evaluations for the component and piping sentinel locations determined all CUF_{en} values remained below the acceptance criteria of 1.0 with two (2) exceptions; 1) the pressurizer spray nozzle, and 2) the steam generator tubes. The component and piping sentinel locations with CUF_{en} values < 1.0, will be managed by the PBN Fatigue Monitoring AMP (Section 16.2.1.1) through the use of cycle counting. The PBN Fatigue Monitoring AMP will monitor the transient cycles and severities which are the inputs to the EAF evaluations and require action prior to exceeding design limits that would invalidate their conclusions.

For the pressurizer spray nozzle, the effects of fatigue will be managed by application of the In-service Inspection program (PBN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section 16.2.2.1)) during the subsequent period of operation based on results of flaw tolerance evaluation conducted in accordance with the guidance of ASME Code, Section XI, Nonmandatory, Appendix L. The ASME Code, Section XI, Appendix L crack growth evaluation is used in conjunction with calculated allowable flaw sizes to determine the required inspection interval for a postulated flaw in the piping at the bounding location.

For the steam generator primary side tube location, the effects of fatigue will be managed by the PBN Steam Generators AMP (Section 16.2.2.10). The program requires that the steam generator tubes be volumetrically examined such that fatigue cracks will be detected, and corrective actions will be initiated as appropriate to maintain the intended functions.

Therefore, the component and piping EAF evaluations will be adequately managed for the SPEO operation in accordance with 10 CFR 54.21(c)(1)(iii).

16.3.4. Environmental Qualification of Electric Equipment

Thermal, radiation, and cyclical aging analyses of plant electrical and instrumentation components, developed to meet 10 CFR 50.49 requirements, have been identified as TLAAs. The NRC has established EQ requirements in 10 CFR 50.49 and 10 CFR Part 50, Appendix A, Criterion 4. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of in-service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a LOCA, HELB, or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification. Aging evaluations for electrical components in the EQ Program that specify a qualification of at least 60 years have been identified as TLAAs for license renewal because the criteria contained in 10 CFR 54.3 are met.

The PBN Environmental Qualification of Electric Equipment AMP (Section 16.2.1.4) meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of components within the scope of the program, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics and the environmental conditions to which the components could be subjected during their service life.

10 CFR 50.49(e)(5) contains provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect component functional capability. 10 CFR 50.49(e)(5) also requires replacement or refurbishment of components not qualified for the current license term prior to the end of designated life, unless additional life is established through ongoing qualification.
10 CFR 50.49(f) establishes four methods of demonstrating qualification for aging and accident conditions. 10 CFR 50.49(k) and (l) permit different qualification criteria to apply based on plant and component vintage. Supplemental EQ regulatory guidance for compliance with these different qualification criteria is provided in the

Division of Operating Reactors (DOR) Guidelines, NUREG-0588, and NRC Regulatory Guide (RG) 1.89, Revision 1.

The PBN Environmental Qualification of Electric Equipment AMP (Section 16.2.1.4) will manage the effects of aging effects for the components associated with the EQ TLAA. This program implements the requirements of 10 CFR 50.49 (as further defined and clarified by NUREG-0588 and RG 1.89, Revision 1). Component aging evaluations are reanalyzed on a routine basis to extend the qualifications of components. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). The reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid.

The PBN Environmental Qualification of Electric Equipment AMP (Section 16.2.1.4) has been demonstrated to be capable of programmatically managing the aging of the electrical and instrumentation components in the scope of the program. Therefore, aging will be adequately managed for the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

16.3.5. <u>Concrete Containment Unbonded Tendon Prestress</u>

The PBN Units 1 and 2 containment buildings are post-tensioned, reinforced concrete structures composed of vertical cylinder walls and a shallow dome, supported on a conventional reinforced concrete base slab. The cylinder walls are provided with vertical tendons and horizontal hoop tendons. The dome is provided with three groups of tendons oriented 120-degrees apart. Over time, the containment prestressing forces decrease due to relaxation of the steel tendons and due to creep and shrinkage of the concrete. The containment tendon prestressing forces were calculated during the original design considering the magnitude of the tendon relaxation and concrete creep and shrinkage over the 40-year life of the plant.

Predicted force values are calculated for each tendon prior to periodic surveillances to estimate the magnitude of the tendon relaxation and concrete creep and shrinkage for the given surveillance period. The prestressing forces are measured and plotted, and trend lines are developed, to ensure the average tendon group prestressing values remain above the respective minimum required values (MRVs) until the next scheduled surveillance. The predicted force values and regression analyses, utilizing actual measured tendon forces, are used to evaluate the acceptability of the containment structure to perform its intended function.

The methodology used in this TLAA follows the same methodology used in developing the calculation for original license renewal. The upper bound and lower bound tendon lift-off force curves for the 80-year lifetime are developed in accordance with Regulatory Guide 1.35 and Regulatory Guide 1.35.1. An allowance of 1 percent is considered for wire breakage in developing the lower bound lift-off force curves, consistent with the original license renewal evaluation. The lower bound tendon lift-off force curves developed in the original license renewal evaluation are adjusted to account for 1 percent allowance for wire breakage at 80 years of operating life.

The PBN Prestressed Concrete Containment Tendon Surveillance AMP (Section 16.2.1.3) is a confirmatory program that monitors the loss of prestressing forces in containment tendons throughout the life of the plant. This program consists of an assessment of the results of the tendon prestressing force measurements performed in accordance with the PBN ASME Section XI, Subsection IWL AMP (Section 16.2.2.30). Regression analyses are performed to obtain the trendlines which fit the measured tendon force data most accurately in order to forecast the tendon forces for the extended 80-year operating life. For each tendon group, the measured tendon force data, the trendlines obtained from regression analyses, the upper and lower bound lift-off force curves and the minimum required tendon forces are plotted in log-linear time-force plots for the 80-year SPEO.

The forecasted tendon forces for the 80-year SPEO are higher than the minimum required tendon forces. Furthermore, the lower bound curves for all dome, hoop and vertical tendons remain above the minimum required tendon forces. Consequently, the trendlines remain above the minimum required tendon forces for all containment tendons. In conclusion, the predicted tendon prestressing forces at 80 years of service life will be adequate to maintain the structural integrity of the containment post-tensioning system.

The concrete containment tendon prestress analysis has been projected to the end of the SPEO. Additionally, the PBN Concrete Containment Unbonded Tendon Prestress AMP (Section 16.2.1.3) and the PBN ASME Section XI, Subsection IWL AMP (Section 16.2.2.30) will manage the effects of aging related to prestress forces on the containment tendon prestressing system in accordance with 10 CFR 54.21(c)(1)(iii).

16.3.6. <u>Containment Liner Plate and Penetrations Fatigue Analysis</u>

The interior of each PBN containment is lined with welded steel plates to provide an essentially leak-tight barrier. Design criteria are applied to the liner plate to assure that the specified allowed containment leak rate is not exceeded under design basis accident conditions. The following fatigue loads, as described in UFSAR Section 5.1.2.2, were considered in the design of the liner plate and are considered a TLAA:

1. Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is 60 for the current plant life of 60 years.

2. Thermal cycling due to containment interior temperature varying during the startup and shutdown of the reactor system. The number of cycles for this loading is assumed to be 500.

3. Thermal cycling due to the design basis accident is assumed to be one cycle.

4. Thermal load cycles in the piping system are somewhat isolated from the liner plate penetrations by concentric sleeves between the pipe and the liner

plate. The attachment sleeves are designed in accordance with ASME Boiler and Pressure Vessel Code, Section III, fatigue considerations.

For item one, the number of thermal cycles due to annual outdoor temperature variations was increased from 60 to 80 for the SPEO. The effect of this increase is insignificant in comparison to the assumed 500 thermal cycles due to containment interior temperature varying during heatup and cooldown of the reactor coolant system (RCS). The 500 thermal cycles includes a margin of 300 thermal cycles above the 200 allowable RCS design heatup and cooldown cycles, which is sufficient margin to accommodate the additional 20 cycles of annual outdoor temperature variation.

For item two, the assumed 500 thermal cycles was evaluated based on the more limiting heatup and cooldown design cycles (transients) for the major components of the RCS. As indicated in Table 4.1-8 of the PBN UFSAR, the major components of the RCS were designed to withstand 200 heatup and cooldown cycles and is conservative enough to envelop the projected cycles for the SPEO.

For item three, the assumed value for thermal cycling due to the design basis accident remains valid. No maximum design basis accident has occurred to date and none is expected, therefore, this assumption is considered valid for the SPEO.

For item four, the design of the containment piping penetrations was previously reviewed as part of the original PBN license renewal application and the EPU project. The containment penetrations were designed, fabricated, inspected, and tested in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class B, 1968 edition and all addenda. The main steam, feedwater, blowdown, and letdown systems are the only piping systems penetrating the containment that contribute significant thermal loading on the liner plate. Due to the higher operating temperature, the main steam piping penetration was considered bounding and was therefore analyzed for fatigue through the SPEO. The analysis of the main steam piping penetration sleeve and the sleeve end fitting connecting the pressure piping to the sleeve verified that the six conditions of ASME Code, Section III, Subsection A, N 415.1, 1965, are satisfied for the PEO and a fatigue analysis of the piping penetrations is not required.

PBN has been unable to locate the original fatigue analysis or confirm if a fatigue waiver exists for the PBN containment penetrations other than piping penetrations, piping penetrations with dissimilar metal welds, and for the expansion joints of the containment structure reactor fuel transfer tube. Therefore, consistent with NUREG-2192, cracking due to cyclic loading of non-piping containment penetrations will be managed by the PBN ASME Section XI, Subsection IWE AMP (Section 16.2.2.29) and periodic supplemental surface examinations incorporated into and consistent with the frequency of the PBN 10 CFR Part 50, Appendix J AMP (Section 16.2.2.32).

Therefore, the fatigue analyses associated with the containment liner plate and piping penetrations have been evaluated and determined to remain valid for the SPEO in accordance with 10 CFR 54.21(c)(1)(i). The fatigue analyses associated with the containment personnel airlocks, equipment hatch, personnel hatch, electrical penetrations, piping penetrations with dissimilar metal welds, and expansion joints of the containment structure fuel transfer tube on each unit will be managed by the PBN ASME Section XI, Subsection IWE AMP (Section 16.2.2.29) and the PBN 10 CFR Part 50, Appendix J AMP (Section 16.2.2.32) in accordance with 10 CFR 54.21(c)(1)(iii).

16.3.7. Other Site-Specific TLAAs

16.3.7.1. Leak-Before-Break of Reactor Coolant System Loop Piping

In 1996, Westinghouse performed a plant specific primary loop piping leak-before-break (LBB) analysis for PBN Units 1 and 2. The results of the analysis were documented in WCAP-14439. In 2003, the LBB analysis was updated to address license renewal for the 60-year period of extended operation. In 2008, the 2003 primary loop piping LBB analysis conclusions were re-examined for the PBN EPU project. The results of 2008 EPU evaluation concluded the 2003 analysis remained applicable for the EPU project.

WCAP-14439-P, Revision 3 performed the LBB evaluation for an 80-year plant life. The analysis documented the plant-specific geometry, loading, and material properties used in the fracture mechanics evaluation. The updates performed for WCAP-14439-P, Revision 3 included a recalculation of delta ferrite and fracture toughness properties based on NUREG/CR-4513. The chemistry data for the fracture mechanics parameters are obtained from the primary loop elbow fitting Certified Materials Test Reports (CMTRs). Fracture toughness parameters were recalculated using information from NUREG/CR-4513.

The fatigue crack growth analysis used the original 40-year CLB design cycles. As discussed in Section 16.3.3.1, the 40-year design cycles (CLB cycles) bound 80 years of plant operations. Therefore, the fatigue crack growth analysis for the LBB analysis has been projected to the end of the SPEO.

WCAP-14439-P, Revision 3, provides the fracture mechanics demonstration of the reactor coolant system primary loop integrity consistent with the NRC position for exemption from consideration of dynamic effects noted in NUREG-0800, Section 3.6.3. The analysis justifies the elimination of reactor coolant system primary loop pipe breaks from the structural design basis for the 80-year plant life.

The analysis performed in WCAP-14439-P, Revision 3 determined that the crack stability results, fracture toughness, and fatigue crack growth results are acceptable for 80 years of plant operation. Therefore, the LBB analysis is projected through the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

16.3.7.2. Leak-Before-Break of Reactor Coolant System Auxiliary Piping

In 2001, Westinghouse performed plant specific LBB evaluations for the PBN Units 1 and 2 pressurizer surge line, residual heat removal (RHR) line, and accumulator line. In 2008, Westinghouse re-evaluated these LBB evaluations as part of the PBN EPU project. That evaluation was based on EPU loadings, operating pressure and temperature parameters and concluded that the three (3) LBB evaluations remained valid for the EPU conditions.

The aging effects that must be addressed for SLR include the potential for thermal aging of the piping components and fatigue crack growth. Thermal aging refers to the gradual change in the microstructure and properties of a material due to its exposure to elevated temperatures for an extended period of time. The only significant thermal aging effect on the auxiliary line piping components would be embrittlement of any duplex ferritic CASS components. The PBN pressurizer surge lines, RHR lines and accumulator lines do not contain any duplex ferritic CASS materials. Therefore, thermal aging of these Class 1 piping components is not applicable for SLR.

Based on loading, piping geometry, and fracture toughness considerations, enveloping critical locations were determined for the Class 1 auxiliary lines at which LBB crack stability evaluations were made. Through-wall flaw sizes were postulated at the critical locations that would cause leakage at a rate ten times the leakage detection system capability and large margins against flaw instability were demonstrated for the postulated flaw sizes. The RCS auxiliary line LBB fatigue evaluations assumed the PBN 40-year design cycles for Class 1 components. As discussed in Section 16.3.3.1, the 80-year projected cycles for SLR are significantly less than the original PBN 40-year design cycles. Therefore, the fatigue crack growth evaluations and results remain valid for the SPEO.

The LBB analyses associated with the pressurizer surge line, residual heat removal line, and accumulator line have been evaluated and determined to remain valid for the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

16.3.7.3. Flaw Tolerance Evaluation for Reactor Coolant Loop CASS Piping Components

The PBN Units 1 and 2 reactor coolant loop piping elbows are constructed from CASS material. CASS material is susceptible to thermal aging at the normal reactor operating temperature. Thermal aging of CASS material results in embrittlement, that is, a decrease in the ductility, impact strength, and fracture toughness of the material. In July of 2005, Westinghouse developed flaw tolerance evaluation for the CASS reactor coolant loop (RCL) piping elbows in accordance with the requirements of ASME Code, Section XI. The evaluation considered the effect of thermal aging and included a fatigue crack growth evaluation based on plant-specific design transients and cycles that are applicable to PBN.

For SLR, the flaw tolerance evaluation has been updated for the 80-year SPEO. The evaluation includes plant-specific geometry, loading, material properties, and stresses used in the fracture mechanics evaluation. The susceptibility of CASS piping components to thermal aging is determined according to molybdenum content, casting methods, and delta ferrite content. In determining susceptibility of the CASS piping elbows to thermal aging, the delta ferrite content for PBN is estimated using Hull's Equivalent Factor in NUREG/CR-4513, Revisions 1 and 2.

The evaluation procedures and acceptance criteria, contained in paragraph IWB-3640 of the ASME Section XI Code, are used to determine the maximum allowable flaw size at the end of the inspection/evaluation period. A fatigue crack growth analysis is then performed considering the requirements for the thermal transients and the design or projected cycles for the 80-year service life. Thermal transients and the number of cycles applied during the design life of the plants are required in performing fatigue crack growth analysis. The fatigue crack growth analysis used the original 40-year CLB design cycles. As discussed in Section 16.3.3.1, the 40-year design cycles (CLB cycles) bound 80 years of plant operations.

Bounding evaluations applicable to both PBN Units 1 and 2 were performed for the susceptible elbow locations in each reactor coolant loop. The objective of the flaw tolerance evaluation is to demonstrate that even with thermal aging, the susceptible CASS components are flaw tolerant for 80 years of service. The maximum acceptable initial flaw depths in all CASS components were determined to be deeper than the allowable flaw standards for the volumetric examination method in Section XI of the ASME Code. Even with thermal aging in the susceptible PBN reactor coolant loop CASS piping elbows, the susceptible piping locations have been shown to be tolerant of large flaws for 80-year plant life.

Therefore, the flaw tolerance evaluation is projected through the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

16.3.7.4. Reactor Coolant Pump Flywheel Fatigue Crack Growth

During normal operation, the reactor coolant pump flywheel possesses sufficient kinetic energy to potentially produce high-energy missiles in the unlikely event of failure. Conditions that may result in overspeed of the reactor coolant pump increase both the potential for failure and the kinetic energy. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway.

An evaluation of the probability of failure over the 60-year period of extended operation was performed in WCAP-14535-A, for all operating Westinghouse plants. The evaluation demonstrated that the flywheel design has high structural reliability with a very high flaw tolerance and negligible flaw crack extension over a 60-year service life. The NRC reviewed and approved the evaluation with certain conditions and limitations. PBN verified the RCP flywheel material and invoked this analysis as the basis for reducing the frequency of performing RCP flywheel inspections for the 60-year PEO. WCAP-15666-A, Revision 1, builds on the arguments in WCAP-14535-A and provides additional rationale, including a risk assessment of all credible flywheel speeds. The NRC approved the use of this Topical Report in an NRC Safety Evaluation Report (SER). This analysis was used as a basis for a revision of PBN Technical Specification TS 5.5.6 which increased the flywheel inspection interval from 10 years to 20 years.

An evaluation of the probability of failure over the SPEO was performed by the PWROG. Evaluation PWROG-17011-NP-A confirms that the analyses performed under WCAP-14535-A and WCAP-15666-A justifying inspection of the RCP flywheel once every 20-years remains appropriate for application up to 80 years of operation. The evaluation demonstrates that the RCP flywheel design has a high structural reliability with a very high flaw tolerance and negligible fatigue flaw crack extension over an 80-year service life.

The RCP flywheel fatigue crack growth analysis has been demonstrated to remain valid through the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

16.3.7.5. Reactor Coolant Pump Code Case N-481

The PBN reactor coolant pumps (RCPs) are model 93A with SA-351, Grade CF-8 pump casings. ASME Code Case, N-481 allowed the replacement of volumetric examinations of primary loop pump casing welds with fracture mechanics-based integrity evaluations supplemented by specific visual inspections. During the early 1990's when the Code Case N-481 was approved by the ASME, the Westinghouse Owners Group (WOG) performed a generic fracture mechanics analysis per the Code Case for the various primary loop pump casing models found in Westinghouse-designed plants. The generic fracture mechanics analyses are documented in WCAP-13045. Although Code Case N-481 has been annulled in Regulatory Guide 1.147, the analysis supporting it is a TLAA.

Loss of fracture toughness due to thermal aging embrittlement of CASS RCP casings is identified as an aging mechanism in NUREG-2191 and provides an allowance for continued use of flaw tolerance evaluations performed as part of implementation of Code Case N-481 to address thermal aging embrittlement and states that no further actions are needed if applicants demonstrate that the original flaw tolerance evaluation performed as part of Code Case N-481 implementation remains bounding and applicable for the SLR period or the evaluation is revised to be applicable for 80 years.

For SLR, an update to WCAP-13045 was completed in the PWROG report PWROG-17033-P-A. The NRC approved PWROG-17033-P-A for SLR and provided conditions on the plant-specific applicability of the report in terms of assessing the plant-specific loadings, material fracture toughness and transients. Reconciliation report LTR-SDA-20-020-NP was performed by Westinghouse for the PBN RCP casings to address the CASS thermal aging embrittlement concern for the SPEO. The latest plant-specific piping loads and 80-year design transients and cycles were considered in the analysis to satisfy NRC conditions.

The results presented in report LTR-SDA-20-020-NP justify the plant-specific applicability of PWROG-17033-P-A and WCAP-13405 for the PBN RCP casings and the PBN RCP casings are in compliance with ASME Code Case N-481 for the SPEO.

Therefore, the analysis associated with ASME Code Case N-481 has been demonstrated to remain valid through the SPEO in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

16.3.7.6. Crane Load Cycle Limits

A review of design specifications for cranes within the scope of SLR was performed to identify those cranes that were designed or otherwise required to meet the intent of the Crane Manufacturers Association of America (CMAA) Specification 70-1975 and, therefore, have defined service life as measured in load cycles.

The cranes potentially subject to TLAA are those in compliance with NUREG-0612. As documented in UFSAR Appendix A.3, the following cranes comply with NUREG-0612 and are included in SLR scope:

- Containment polar cranes
- Auxiliary building crane
- Turbine building crane

CMAA Specification 70 presents the bounding combinations of the number of load cycles and mean effective load factors for each service class. These define the acceptable service limits for the TLAA. Based on the comparison of service classes described in the original PBN crane design specification EOCI Specification 61 to CMAA Specification 70, the applicable service class for the PBN containment polar cranes, auxiliary building cranes, and turbine building crane is Class A. Table 2.8-1 of CMAA Specification 70 states that a range of load cycles from 20,000 to 100,000 was considered for cranes in Service Class A service thus establishing the envelope for the acceptable number of load cycles for this TLAA.

The total projected 80-year load cycles for the PBN cranes within the scope of this TLAA are as follows:

- Containment polar cranes – 96,000 load cycles
- Auxiliary building crane – 8,384 load cycles

Both of these 80-year load cycles are less than the 100,000 load cycle limit specified for Class A service. Note that as stated in Section 4.3.13 of NUREG-1839, the primary auxiliary building cranes and the containment cranes are limiting for load lifts. Therefore, they bound the load lifts for the turbine building crane.

The containment polar cranes, auxiliary building cranes, and turbine building crane load cycles remain valid through the SPEO in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

16.4. Subsequent License Renewal (SLR) Commitments List

Table 16-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
1	Fatigue Monitoring (16.2.1.1)	X.M1	Continue the existing PBN Fatigue Monitoring AMP, including enhancement to: a) Update the plant procedure to monitor chemistry parameters that provide inputs to F_{en} factors used in CUF_{en} calculations. b) Update the plant procedure to identify and require monitoring of the 80-year projected plant transients that are utilized as inputs to CUF_{en} calculations. c) Update the plant procedure to identify the corrective action options to take if component specific fatigue limits are approached.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032
2	Neutron Fluence Monitoring (16.2.1.2)	X.M2	Continue the existing PBN Neutron Fluence Monitoring AMP, including enhancement to: a) Follow the related industry efforts, such as by the PWROG, and use the information from supplemental nozzle region dosimetry measurements and reference cases or other information to provide additional justification for use of the approved WCAP-16083 (equivalent to WCAP-14040-A) or similar methodology for determination of RPV fluence in regions above or below the active fuel region. b) Draw from Westinghouse's NRC approved RPV fluence calculation methodology and include discussion of the neutron source, synthesis of the flux field and the order of angular quadrature (e.g., S8), etc. used in the estimates for projection of TLAAs to 80 years.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032
3	Concrete Containment Unbonded Tendon Prestress (16.2.1.3)	X.S1	Continue the PBN Concrete Containment Unbonded Tendon Prestress AMP including enhancement to: a) Formalize the update of prestress calculations and trend lines after each scheduled "physical" inspection, which includes monitoring of tendon forces, in accordance with RG 1.35.1.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32

Table 16-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			b) Include the 80-year prestress calculation with or in place of the current, 60-year, acceptance limits in the program plan for each scheduled IWL inspection interval.	
4	PBN Environmental Qualification of Electric Equipment (16.2.1.4)	X.E1	Continue the existing PBN Environmental Qualification of Electric Equipment AMP, including enhancement to: a) Visually inspect accessible, passive EQ equipment for adverse localized environments that could impact qualified life at least once every 10 years with the first periodic visual inspection being performed prior to the SPEO.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32
5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (16.2.2.1)	XI.M1	Continue the existing PBN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP, including enhancement to: a) Perform In-service inspections of the PBN Units 1 and 2 ASME Code, Section XI, Appendix L pressurizer spray nozzle safe end piping at least once in each 10-year ISI interval with the first periodic inspection being performed no earlier than 10 years prior to the SPEO and no later than the last refueling outage prior to the SPEO.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032 Implement the AMP and start Appendix L inspections and tests no earlier than 10 years prior to the SPEO.
6	Water Chemistry (16.2.2.2)	XI.M2	Continue the existing PBN Water Chemistry AMP, including enhancements to: a) Incorporate monitoring the critical chemistry parameters for the Heating Steam System in accordance with industry standards, specifically ASME standard ISBN-0-7918-1204-9, "Consensus on Operating Practices for the Control of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers." b) Perform a one-time inspection to verify the effectiveness of monitoring the critical chemistry parameters for the Heating Steam Systems in accordance with industry standards, specifically ASME stands ISBN-0-	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032

Table 16-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			7918-1204-9, "Consensus on Operating Practices for the Control of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers."	
7	Reactor Head Closure Stud Bolting (16.2.2.3)	XI.M3	Continue the existing PBN Reactor Head Closure Stud Bolting AMP, including enhancement to: a) Revise the procurement requirements for reactor head closure stud material to assure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032
8	Boric Acid Corrosion (16.2.2.4)	XI.M10	Continue the existing PBN Boric Acid Corrosion AMP, including enhancement to: a) Coordinate with the PBN Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components AMP regarding evidence of boric acid residue (plating out of moist steam) <u>inside</u> containment cooler housings or similar locations such as cooling unit drain pans.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032
9	Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (16.2.2.5)	XI.M11B	Continue the existing PBN Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP, including enhancement to: a) Update the plant modification process to ensure that no additional nickel alloys will be used in reactor coolant pressure boundary applications during the SPEO or that, if used, appropriate baseline and subsequent inspections per MRP inspection guidance will be put in place.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032
10	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (16.2.2.6)	XI.M12	Implement the new PBN Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032

Table 16-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
11	Reactor Vessel Internals (16.2.2.7)	XI.M16A	Continue the existing PBN Reactor Vessel Internals AMP, including enhancement to: a) Implement the guidance in MRP 227 Rev. 1 A as supplemented by the gap analysis, or the latest NRC approved version of MRP 227 which addresses 80 years of operation if one is available prior to the subsequent period of extended operation. b) Implement the results of the gap analysis in the Reactor Vessel Internals Program unless it is superseded by the latest NRC approved version of MRP 227 which addresses 80 years of operation. If so, the AMP may be implemented directly without the use of a gap analysis. c) Incorporate the updated examination acceptance criteria, Primary / Expansion links, expansion criteria, and expansion item examination criteria in MRP 227 Rev. 1 A as supplemented by the gap analysis.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032
12	Flow-Accelerated Corrosion (16.2.2.8)	XI.M17	Continue the existing PBN Flow-Accelerated Corrosion AMP, including enhancement to: a) Reassess piping systems excluded from wall thickness monitoring due to operation less than 2% of plant operating time (as allowed by NSAC-202L) to ensure the exclusion remains valid and applicable for operation beyond 60 years. b) Formalize a separate erosion susceptibility evaluation (ESE) that will include all components determined to be susceptible to wall loss due to erosion through OE and industry guidance. c) Perform or compile baseline inspections of erosion susceptible locations where site OE indicates periodic monitoring may be warranted instead of design or operational correction to eliminate the cause of erosion.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032

Table 16-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			d) Revise or develop procedural guidance relative to erosion based on the results that includes – • Components treated in a manner similar to "susceptible-not-modeled" lines discussed in NSAC-202L. • Consideration of EPRI 1011231 for identifying potential damage locations and EPRI TR-112657 and/or NUREG/CR–6031 guidance for cavitation erosion as warranted. e) Revise or provide procedure(s) for measuring wall thickness due to erosion. Wall thickness should be trended to adjust the monitoring frequency and to predict the remaining service life of the component for scheduling repairs or replacements. f) Revise or provide procedure(s) to evaluate inspection results to determine if assumptions in the extent-of-condition review remain valid. If degradation is associated with infrequent operational alignments, such as surveillances or pump starts/stops, then trending activities should consider the number or duration of these occurrences. g) Revise or provide procedure(s) to perform periodic wall thickness measurements of replacement components until the effectiveness of corrective actions have been confirmed. h) Include long-term corrective actions for erosion mechanisms. The effectiveness of the corrective actions should be verified. Include periodic monitoring activities for any component replaced with an alternative material since no material is completely resistant to erosion.	
13	Bolting Integrity (16.2.2.9)	XI.M18	Continue the existing PBN Bolting Integrity AMP, including enhancement to: a) Enhance plant procedures to replace references to NP-5067 Volumes 1 and 2 and EPRI TR-104213 with EPRI Reports 1015336 and 1015337 and incorporate the guidance as appropriate; b) Enhance plant procedures to ensure MoS_2 lubricant will not be used for pressure retaining bolting;	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032

Table 16-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			c) Enhance plant procedures to ensure bolting material with a yield strength greater than or equal to 150 ksi (1,034 MPa) or for which yield strength is unknown will not be used in pressure retaining bolting. If closure bolting greater than 2 inches in diameter (regardless of code classification) with actual yield strength greater than or equal to 150 ksi (1,034 MPa) or for which yield strength is unknown is used, volumetric examination will be required in accordance to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 acceptance standards, extent, and frequency of examination; d) Create a new plant procedure to perform alternative means of testing and inspection for closure bolting where leakage is difficult to detect (e.g., piping systems that contain air or gas or submerged bolting); e) Enhance plant procedures to ensure that bolted joints that are not readily visible during plant operations and refueling outages will be inspected when they are made accessible and at such intervals that would provide reasonable assurance the components' intended functions are maintained. Plant procedures for visual inspections and examinations will be revised to include the bolting integrity program in their scope; f) Enhance plant procedures to project, where practical, identified degradation until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation. For sampling-based inspections, results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation. Adverse results will be evaluated to determine if an increased sample size or inspection frequency is required;	

Table 16-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			g) Enhance plant procedures to include the requirements for leakage monitoring, sample expansion and additional inspections if inspection results do not meet acceptance criteria.	
14	Steam Generators (16.2.2.10)	XI.M19	Continue the existing PBN Steam Generators AMP, including enhancement to: a) If the Unit 1 steam generator divider plate assemblies are not bounded by industry analyses EPRI 3002002850, perform one-time inspections of the Unit 1 steam generator divider plate assemblies prior to the SPEO.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032
15	Open-Cycle Cooling Water System (16.2.2.11)	XI.M20	Continue the existing PBN Open-Cycle Cooling Water System AMP, including enhancement to: a) Update the primary program documents and procedures and applicable preventive maintenance requirements to clearly identify the portions of the service water system, within the scope of GL 89-13, where flow monitoring is not performed. For these portions of the service water system, the procedures will calculate friction (or roughness) factors based on test results from the flow monitored portions of the service water system and use these factors to confirm that design flow rates will be achieved with the overall fouling identified in the system. b) Update the primary program documents and procedures and applicable preventive maintenance requirements to clearly identify the inspections and tests that are within the scope of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) and those inspections and tests that are not. The procedures and preventive maintenance requirements that perform the ASME Code inspections and tests shall be consistent with and reference the respective ASME Code. The procedures and preventive maintenance requirements that perform the Non-ASME Code inspections and tests shall follow site procedures that include requirements for items such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes. c) Update the primary program documents and procedures and applicable PMRQs to state that examinations of polymeric materials (i.e., neoprene expansion joints) shall include visual and tactile inspections whenever the	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032

Table 16-3
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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			component surfaces are accessible during the performance of periodic surveillances or during maintenance activities or scheduled outages. These inspections shall check for surface cracking, crazing, discoloration, scuffing, loss of material due to wear, dimensional change, and exposure of reinforcing fibers/mesh/metal. Manual or, physical manipulation or pressurization of flexible polymeric components is used to augment visual inspection, where appropriate, to assess loss of material or strength. The sample size for manipulation is at least 10% of accessible surface area, including visually identified suspect areas. Hardening, loss of strength, or loss of material due to wear is expected to be detectable before any loss of intended function. d) Update the primary program documents and procedures and applicable preventive maintenance requirements to perform trending of the observed or calculated friction (or roughness) factors to confirm that the design flow rates will be achieved in the portions of the service water system, within the scope of GL 89-13, where flow monitoring is not performed. e) Update the primary program documents and procedures and applicable preventive maintenance requirements to clarify that when previous pipe wall thickness measurements are not available for the determination of a corrosion rate, a corrosion rate that has been calculated from other locations with nearly identical operating conditions, material, pipe size, and configuration may be used to determine re-inspection intervals. This corrosion rate assignment must be documented in an Engineering Evaluation to document the location(s) used, basis for correlation, and final corrosion rate assigned. A mill tolerance of 12.5% shall be used for added conservatism when establishing an initial wall thickness value when determining corrosion rates at new inspection locations if corrosion rates at other locations with nearly identical operating conditions, material, pipe size, and configuration cannot be used. f) Update the primary program documents and procedures and applicable preventive maintenance requirements to clarify that if fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage,	

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			loss of material, and chemical treatment effectiveness. For ongoing degradation mechanisms (e.g., MIC and erosion) or recurring loss of material due to internal corrosion, the frequency and extent of wall thickness inspections are increased commensurate with the significance of the degradation. The number of increased inspections is determined in accordance with the PBN corrective action program; however, no fewer than five additional inspections are conducted for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination is inspected, whichever is less. Since PBN is a two-unit site, the additional inspections include inspections of components with the same material, environment, and aging effect combination at the opposite unit. The additional inspections will occur at least every 24 months until the rate of recurring internal corrosion occurrences no longer meets the criteria for "loss of material due to recurring internal corrosion" as defined in NUREG-2192. The selected inspection locations will be periodically reviewed to validate their relevance and usefulness and adjusted as appropriate. Evaluation of the inspection results will include (1) a comparison to the nominal wall thickness or previous wall thickness measurements to determine rate of corrosion degradation; (2) a comparison to the design minimum allowable wall thickness to determine the acceptability of the component for continued use; and (3) a determination of reinspection interval.	
16	Closed Treated Water Systems (16.2.2.12)	XI.M21A	Continue the existing PBN Closed Treated Water Systems AMP, including enhancement to: a) Ensure that the new visual inspection procedure(s) and/or preventive maintenance requirements evaluate the visual appearance of surfaces for evidence of loss of material. b) Create new procedure(s) and/or preventive maintenance requirements that perform surface or volumetric examinations and evaluate the examination results for surface discontinuities indicative of cracking. c) Create visual inspection procedure(s) and/or preventive maintenance requirements, for heat exchangers that are unable to be functionally tested,	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032

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			to determine the tube surface cleanliness and verify that design heat removal rates are maintained. d) Ensure that visual inspections of closed treated water system components' internal surfaces are conducted whenever the system boundary is opened. The ongoing opportunistic visual inspections can be credited towards the representative samples for the loss of material and fouling; however, surface or volumetric examinations must be used to confirm that there is no cracking. e) Create new procedure(s) and/or preventive maintenance requirements to ensure that the inspection requirements from NUREG-2191 are met. At a minimum, in each 10-year period during the SPEO, a representative sample of components is inspected using techniques capable of detecting loss of material, cracking, and fouling, as appropriate. The sample population is defined as follows: • 20% of the population (defined as components having the same material, water treatment program, and aging effect combination) OR; • A maximum of 19 components per population at each unit, since Point Beach is a two-unit plant. f) Ensure that the new inspection and test procedure(s) and/or preventive maintenance requirements will evaluate their respective results against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation. Where practical, identified degradation is projected through the next scheduled inspection. g) Ensure that the new inspection and test procedure(s) and/or preventive maintenance requirements identify and evaluate any detectable loss of material, cracking, or fouling per the PBN corrective action program.	

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			h) Ensure that the following additional inspections and actions are required if a post-repair/replacement inspection or subsequent inspection fails to meet acceptance criteria: • The number of increased inspections is determined in accordance with the PBN corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination is inspected, whichever is less. • If subsequent inspections do not meet acceptance criteria, an extent-of-condition and extent-of-cause analysis is conducted to determine the further extent of inspections. • Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. Since Point Beach is a two-unit site, the additional inspections include inspections at both units with the same material, environment, and aging effect combination. • The additional inspections are completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.	
17	Inspection of Overhead Heavy Load Handling Systems (16.2.2.13)	XI.M23	Continue the existing PBN Inspection of Overhead Heavy Load Handling Systems AMP, including enhancement to: a) Ensure that NUREG-0612 load handling systems are clearly recognized in the governing procedure. b) Ensure that wear is properly managed for all cranes within the scope of SLR.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			c) Align procedures with the 2005 Edition of ASME B30.2, or other applicable industry standard in the ASME B30 series, to ensure that the correct acceptance criteria and corrective actions are used to evaluate (and repair, if necessary) any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload for NUREG-0612 load handling systems. Aligning with the 2005 Edition of ASME B30.2 also ensures that visual inspections are performed at the required frequency. According to ASME B30.2, inspections are performed within the following intervals: • "Periodic" visual inspections by a designated person are required and documented yearly for normal service applications per paragraph 2-2.1.1. • A crane that is used in infrequent service, which has been idle for a period of 1 year or more, shall be inspected before being placed in service in accordance with the requirements listed in paragraph 2-2.1.3 (i.e., periodic inspection). d) Update the governing procedure to state that any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload for NUREG 0612 load handling systems is evaluated according to the 2005 Edition of ASME B30.2 or other applicable industry standard in the ASME B30 series. e) Update the governing procedure to state that repairs made to NUREG 0612 load handling systems are performed as specified in the 2005 Edition of ASME B30.2 or other appropriate standard in the ASME B30 series.	
18	Compressed Air Monitoring (16.2.2.14)	XI.M24	Continue the existing PBN Compressed Air Monitoring AMP, including enhancement to formalize compressed air monitoring activities in a new governing procedure addressing the element by element requirements presented in NUREG-2191 Section XI.M24. The following enhancements are also to be included into this procedure and other pertinent documents:	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.:

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			a) Incorporate the air quality provisions provided in the guidance of the EPRI TR-108147 and consider the related guidance in the American Society of Mechanical Engineers (ASME) OM-2012, Division 2, Part 28. b) Inspections of internal air line surfaces with maintenance, corrective, or other activities that involve opening of the component or system (For example, with air start valve inspections, check valve inspections, and relief valve or check valve replacements, or G05 air dryer filter checks). c) Include inspection frequency and inspection methods for the opportunistic inspections with guidance of standards or documents such as ASME OM-2012, Division 2, Part 28. d) Review air quality test results. e) Consider ASME OM-2012, Division 2, Part 28 for monitoring and trending guidance.	PBN1: 04/05/2030 PBN2: 09/08/2032
19	Fire Protection (16.2.2.15)	XI.M26	Continue the existing PBN Fire Protection AMP, including enhancement to: a) Enhance plant procedures to specify that penetration seals will be inspected for indications of increased hardness, shrinkage and loss of strength, b) Enhance plant procedures to specify that any loss of material to the fire damper assembly is unacceptable, c) Enhance plant procedures to specify that well-sealed and robustly secured components and fully enclosed cable tray covers credited to prevent internal fires from propagating outside of the component, and fire proofing material sprayed onto structural steel will be inspected for loss of material, cracking, and changes to elastomer properties as appropriate, d) Enhance plant procedures to add spalling and scaling to the degradation effects for which masonry block walls are inspected, e) Enhance plant procedures to indicate that personnel performing FP inspections will be qualified to do so, f) Enhance plant procedures to state that at least 10% of each **type** of seal will be visually inspected every 18 months,	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			g) Enhance plant procedures to include monitoring and trending of oil collection channels, trenches, and skids credited to mitigate the spread of combustible liquids for cracking and loss of material h) Enhance plant procedures to specify that well-sealed and robustly secured components and fully enclosed cable tray covers credited to prevent internal fires from propagating outside of the component, and fire proofing material sprayed onto structural steel will be inspected every 4.5 years (33% of the population every 18 months), i) Enhance plant procedures to specify that the dry chemical fire extinguishing systems will be inspected semi-annually, j) Enhance plant procedures to specify that the dry chemical fire extinguishing system inspections will be monitored and trended, and k) Enhance plant procedures to require an inspection of an additional 10% of a type of seal when more than 15% of the sample population does not meet any acceptance criteria during the 18-month inspection period.	
20	Fire Water System (16.2.2.16)	XI.M27	Continue the existing PBN Fire Water System AMP activities, including enhancement to: a) Update the governing AMP procedure to clearly state which procedures perform visual inspections for detecting loss of material. Such visual inspections will require using an inspection technique capable of detecting surface irregularities that could indicate an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric wall thickness examinations shall be performed. b) Update the governing AMP procedure to clearly state which procedures perform volumetric wall thickness inspections. Volumetric inspections shall be conducted on the portions of the water-based fire protection system components that are periodically subjected to flow but are normally dry. c) Update existing procedures and create new procedures to perform testing and visual inspections in accordance with the surveillance requirements,	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032 Implement the AMP and start inspections and tests no earlier than 5 years prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			including methods and intervals, from Table XI.M27 1 of NUREG 2191 based on NFPA 25, 2011 Edition. d) Update the governing AMP procedure and trending procedure to state that where practical, degradation identified is projected until the next scheduled inspection. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation. Results of flow testing, flushes, and wall thickness measurements are monitored and trended by either the Engineering or Fire Protection Department per instructions of the specific test/inspection procedure. Degradation identified by flow testing, flushes, and inspections is evaluated. If the condition of the piping/component does not meet acceptance criteria, then a condition report is written per the corrective action program and the component is evaluated for repair/replacement. For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation. e) Update the governing AMP procedure to identify the procedure that performs the continuous monitoring and evaluation of the fire water system discharge pressure. f) Update the governing AMP procedure to state that results of flow testing (e.g., buried and underground piping, fire mains, and sprinkler), flushes, and wall thickness measurements are monitored and trended. Degradation identified by flow testing, flushes, and inspections is evaluated. g) Update governing AMP procedure to state that the minimum design wall thicknesses of the in-scope piping must be maintained.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			h) Update the governing AMP procedure to point to the inspection procedures which inspect the wall thicknesses and compare to the minimum design thicknesses. i) Update the existing flow test procedure and develop a new main drain test procedure to state that if a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation, then additional tests are conducted. The number of increased tests is determined in accordance with the PBN corrective action program; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval (i.e., 5 years, annual) in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent-of-condition and extent-of-cause analysis is conducted to determine the further extent of tests. Since PBN is a multi-unit site, additional tests include inspections at all of the units with the same material, environment, and aging effect combination.	
21	Outdoor and Large Atmospheric Metallic Storage Tanks (16.2.2.17)	XI.M29	Continue the existing PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP, including enhancement to: a) Ensure that caulking or sealant is applied to the concrete-to-tank interface for the FOSTs, T-032A and T-032B, prior to the SPEO. b) Create a new procedure, and/or associated preventive maintenance requirements (PMRQs), to: • Address the interfaces, handoffs, and overlaps between the PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP and the following AMPs: ○ PBN Structures Monitoring AMP; ○ PBN External Surfaces Monitoring of Mechanical Components AMP; ○ PBN Water Chemistry AMP; ○ PBN Fuel Oil Chemistry AMP;	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032 Implement the AMP and start the one-time and 10-year interval inspections no earlier than 10 years prior to the SPEO.

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			○ PBN One-Time Inspection AMP; ○ PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP. • Direct periodic (every refueling outage) visual inspection of FOST to concrete caulking/sealants, with mechanical manipulation as appropriate. • Direct periodic (10-year) surface examination of an RWST's external surface for evidence of cracking, with insulation removed, at the locations most susceptible to degradation and leakage. • Direct periodic (10-year) bottom thickness measurement of an RWST and the RMWT using low-frequency electromagnetic testing (LFET) techniques with follow-on ultrasonic testing (UT) examination, as necessary, at discrete tank locations identified by LFET. • Direct periodic (10-year) visual inspections of an RWST's nonwetted surface for evidence or loss of material and cracking. If evidence of cracking is identified, then a surface examination is also performed to determine the extent of the cracking. For the RMWT, direct periodic (10-year) visual inspections of the RMWT interior above the diaphragm for evidence of loss of material. • Clarify that subsequent inspections are conducted in different locations unless the PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP includes a documented basis for conducting repeated inspections in the same location. • Clarify that inspections and tests are performed by personnel qualified in accordance with site procedures to perform the specified task. • Clarify that non-ASME Code inspections and tests follow site procedures that include considerations such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes.	

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			• Clarify that where practical, identified degradation is projected until the next scheduled inspection.
			• Clarify that results are evaluated against acceptance criteria to confirm or adjust timing of subsequent inspections.
			• State the acceptance criteria as follows:
			  ○ No degradation of paints or coatings (e.g., cracking, flakes, or peeling), or insulation/jacketing, or the RMWT internal diaphragm.
			  ○ No non-pliable, cracked, or missing caulking/sealant for the FOST-concrete interface.
			  ○ No indications of cracking of an RWST.
			  ○ No tank bottom thickness measurements or thickness projections less than the design thickness and/or no exceedance of the corrosion allowance.
			• State the appropriate corrective actions to perform for when degradation (e.g., sealant/caulking flaws, paint/coating flaws, loss of material, cracking, etc.) is identified, which include the following:
			  ○ Report degradation via a condition report (CR) then perform an engineering evaluation.
			  ○ Repair or replace the degraded component as determined by engineering evaluation and perform follow-up examinations.
			  ○ Expand the inspection to include both tanks (for FOST or RWST degradation).
			  ○ Double the sample size (for RWST surface examination degradation).
			Sample expansion inspections that happen in the next inspection interval are part of the preceding interval.	

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			c) Perform baseline LFET tank bottom thickness examinations of a refueling water storage tank and the reactor makeup water tank, with follow-on ultrasonic testing at discrete locations, and a baseline sample surface examination of a refueling water storage tank's exterior (with insulation temporarily removed).	
22	Fuel Oil Chemistry (16.2.2.18)	XI.M30	Continue the existing PBN Fuel Oil Chemistry AMP, including enhancement to: a) Update the frequency for T 072 and G 01 skid/sump tanks internal visual inspections from "on demand" to a 10 year frequency. b) Monitor the following parameters for trending purposes: water content, sediment content, and total particulate concentration for all in-scope tanks. Provide sampling data to the plant quarterly health reports. c) Perform periodic fuel oil sampling of tanks T-031A and B, T-176A and B, T-504, T-505, and the G-01 and G-02 sump/skid-mounted tanks. The sampling methodology shall use either a multilevel sampling technique, such as using an all-level sampling thief or shall obtain a representative sample from the lowest point in the tank if the respective tanks do not allow for multilevel sampling. d) Perform draining and internal visual inspections of the following tanks at least once during the 10-year period prior to the SPEO and repeat the inspection at least once every 10 years: • T-030, P-35B Diesel Driven Fire Pump Fuel Oil Day Tank • T-176A, G-03 EDG Fuel Oil Day Tank • T-176B, G-04 EDG Fuel Oil Day Tank e) Perform volumetric (UT) wall thickness testing, include bottom thickness measurements, of the following tanks at least once during the 10-year period prior to the SPEO and repeat the inspection at least once every 10 years: • T-030, P-35B Diesel Driven Fire Pump Fuel Oil Day Tank • T-031A, G-01 Diesel Generator Day Tank	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032 Implement the AMP and start the one-time and 10-year interval inspections no earlier than 10 years prior to the SPEO.

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			• T-031B, G-02 Diesel Generator Day Tank • T-032A, Fuel Oil Storage Tank • T-032B, Fuel Oil Storage Tank • T-072, Emergency Fuel Oil Storage Tank (buried) • T-176A, G-03 EDG Fuel Oil Day Tank • T-176B, G-04 EDG Fuel Oil Day Tank • T-504, Gas Turbine Generator Starting Diesel Engine Fuel Oil Tank • T-505, G-501 Gas Turbine Generator Auxiliary Power Diesel Engine Fuel Oil Tank • EDG G-01 and G-02 Skid/Sump (Base)-Mounted Tanks (no equipment tag/ID) f) Drain and clean the G-01 and G-02 EDG skid tanks to the best extent practical. Perform visual inspection of accessible locations of the skid tank internals and volumetric (UT) inspection of accessible portions of the skid tank as close to the bottom of the skid tank as possible. This draining, cleaning, and surveillance shall occur at least once during the 10-year period prior to the SPEO and repeat at least once every 10 years. g) Project all identified tank degradation through the next scheduled inspection, where practical. h) Evaluate tank inspection results against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation. i) Report and evaluate all degradation using the corrective action program. Thickness measurements of the tank bottom are evaluated against the design thickness and corrosion allowance. j) Perform corrective actions to prevent recurrence when the specified limits for fuel oil standards are exceeded or when water is drained during periodic surveillance.	

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23	Reactor Vessel Material Surveillance (16.2.2.19)	XI.M31	Continue the existing PBN Reactor Vessel Material Surveillance AMP. Follow the plan for the Supplemental "A" surveillance capsule in accordance with the NRC approved withdrawal schedule.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032
24	One-Time Inspection (16.2.2.20)	XI.M32	Continue the existing PBN One-Time Inspection AMP, including enhancement to: a) Perform visual exams or other appropriate NDE exams to verify the effectiveness of the PBN Lubricating Oil Analysis AMP for managing the effects of aging of various components in systems containing lubricating oil. b) For steel components exposed to water environments that do not include corrosion inhibitors as a preventive action (e.g., treated water, treated borated water, raw water, waste water), verify that long-term loss of material due to general corrosion will not cause a loss of intended function [e.g., pressure boundary, leakage boundary (spatial), structural integrity (attached)]. Long-term loss of material due to general corrosion for steel components need not be managed if one of the following two conditions is met: (i) the environment for the steel components includes corrosion inhibitors as a preventive action; or (ii) wall thickness measurements on a representative sample of each environment will be conducted between the 50th and 60th year of operation. c) Perform one-time volumetric inspections on each of the steam generator transition cone field welds on both units. This one-time volumetric inspection on each steam generator transition cone field weld is intended to cover essentially 100% of the total weld length. d) Perform one-time inspections of the Unit 1 steam generator divider plate assemblies. The inspections will be capable of detecting primary water stress corrosion cracking in the divider plate assemblies and associated welds. e) Inspect a representative sample of each population (defined as components having the same material, environment, and aging effect combination) and, where practical, focus on the bounding or lead	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032 Perform the one time inspections no earlier than 10 years prior to the SPEO and no later than 6 months prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			components most susceptible to aging due to time in service, and severity of operating conditions. A representative sample size is 20% of the population or a maximum of 25 components at each unit. Otherwise, a technical justification of the methodology and sample size used for selecting components for one-time inspection is included as part of the program documentation. Factors that will be considered when choosing components for inspection are time in service, severity of operating conditions, and OE. f) Compare inspection results for each material, environment, and aging effect to those obtained during previous inspections, when available. Where practical, these results are trended in order to project observed degradation to the end of the SPEO. g) Acceptance Criteria: • Consider both the results of observed degradation during current inspections and the results of projecting observed degradation of the inspections for each material, environment and aging effect combinations. • Acceptance criteria may be based on applicable ASME Code or other appropriate standards, design basis information, or vendor-specified requirements and recommendations (e.g., ultrasonic thickness measurements are compared to predetermined limits); however, crack-like indications are not acceptable. • Where it is practical to project observed degradation to the end of the SPEO, the projected degradation will not: (a) affect the intended function of a system, structure, or component; (b) result in a potential leak; or (c) result in heat transfer rates below that required by the CLB to meet design limits. • Where measurable degradation has occurred, but acceptance criteria have been met, the inspection results are entered into the corrective action program for future monitoring and trending.	

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			h) If the cause of the aging effect for each applicable material and environment is not corrected by repair of replacement for all components constructed of the same material and exposed to the same environment, additional inspections are conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections is determined in accordance with the corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination is inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections. Because PBN is a multi-unit site, the additional inspections include inspections at both units with the same material, environment, and aging effect combination. i) Where an aging effect identified during an inspection does not meet acceptance criteria or projected results of the inspections of a material, environment, and aging effect combination do not meet the above acceptance criteria, a periodic inspection program is developed for the specific material, environment, and aging effect combination. The periodic inspection program is implemented at both units with same combination(s) of material, environment, and aging effect.	

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25	Selective Leaching (16.2.2.21)	XI.M33	Implement the new PBN Selective Leaching AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032 Perform the one time inspections no earlier than 10 years prior to the SPEO and no later than 6 months prior to the SPEO.
26	ASME Code Class 1 Small-Bore Piping (16.2.2.22)	XI.M35	Continue the existing PBN ASME Code Class 1 Small-Bore Piping AMP, including enhancement to: a) Perform the new one-time inspection of small-bore piping using the methods, frequencies, and acceptance criteria included in a new program procedure; b) Evaluate the results to determine if additional or periodic inspections are required and perform any required additional inspections.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032 Implement AMP and perform inspections 6 years prior to the SPEO and no later than 6 months prior to the SPEO, or no later than the last RFO prior to the SPEO.
27	External Surfaces Monitoring of Mechanical Components (16.2.2.23)	XI.M36	Continue the existing PBN External Surfaces Monitoring of Mechanical Components AMP, including enhancement to: a) Revise procedure(s) to inspect heat exchanger surfaces exposed to air for evidence of reduction of heat transfer due to fouling. b) Specify in procedure(s) that situations where the similarity of the internal and external environments are such that the external surface condition is	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032

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			representative of the internal surface condition, external inspections of components may be credited for managing: • loss of material and cracking of internal surfaces for metallic and cementitious components, • loss of material, and cracking of internal surfaces for polymeric components, and • hardening or loss of strength of internal surfaces for elastomeric components. When credited, the program provides the basis to establish that the external and internal surface condition and environment are sufficiently similar. c) Clarify in procedure(s) that aging effects associated with below grade components that are accessible during normal operations or refueling outages, for which access is not restricted are managed by the PBN External Surfaces Monitoring of Mechanical Components AMP. d) Revise procedure(s) to include an item in the walkdown checklist to inspect insulation metallic jacketing for any damage that would permit in-leakage of moisture. e) Revise procedure(s) to clarify visual inspection of cementitious components for indications [of] loss of material and cracking. Examples of inspection parameters for cementitious materials include spalling, scaling, and cracking. f) Revise procedure(s) to clarify periodic visual or surface examinations are utilized to manage cracking in stainless steel or aluminum components. g) Revise procedure(s) to add the following inspection parameters for metallic components: • Surface imperfections, loss of wall thickness, oxide coated surfaces • Corrosion stains on thermal insulation • Blistering of protective coating	

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			• Evidence of leakage (for detection of cracks) on the surfaces of stainless steel and aluminum components • Accumulation of debris on heat exchanger tube surfaces and air-side heat exchanger surfaces h) Revise procedure(s) to include inspection for elastomeric and polymeric components and its methodology. Elastomeric and flexible polymeric components are monitored through a combination of visual inspection and manual or physical manipulation of the material. Visual inspections cover 100% of accessible component surfaces. Manual or physical manipulation of the material includes touching, pressing on, flexing, bending, or otherwise manually interacting with the material in order to reveal changes in material properties, such as hardness, and to make the visual examination process more effective in identifying aging effects such as cracking. The sample size for manipulation is at least 10% of available surface area. The inspection parameters for elastomers polymers shall include the following: • Surface cracking, crazing, scuffing, and dimensional change (e.g., “ballooning” and “necking”) • Loss of thickness • Discoloration (evidence of a potential change in material properties that could be indicative of polymeric degradation) • Exposure of internal reinforcement for reinforced elastomers • Hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate to manipulation i) Revise procedure(s) to include that flexing of polyvinyl chloride piping exposed directly to sunlight (i.e., not located in a structure restricting access to sunlight such as manholes, enclosures, and vaults or isolated from the environment by coatings) is conducted to detect potential reduction in impact strength as indicated by a crackling sound or surface cracks when flexed.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			j) Revise procedure(s) to include accumulation of debris on in-scope components is monitored. k) Revise procedure(s) to inspect a sample of HVAC closure bolting in reach to ensure that it is not loose. l) Revise procedure(s) to specify that inspections are to be performed by personnel qualified in accordance with site procedures and programs to perform the specified task, and when required by the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), inspections are conducted in accordance with the applicable code requirements. m) Revise procedure(s) to include inspections for loss of material, cracking, changes in material properties, hardening or loss of strength (of elastomeric components), reduced thermal insulation resistance, loss of preload for ducting closure bolting, and reduction of heat transfer due to fouling at an inspection frequency of every refueling outage for all in-scope non-stainless steel and non-aluminum components, which include metallic, polymeric, insulation jacketing (insulation when not jacketed). Non-ASME Code inspections and tests should include inspection parameters for items such as lighting, distance offset, surface coverage, and presence of protective coatings. Surfaces that are not readily visible during plant operations and refueling outages should be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained. n) Revise procedure(s) to specify that surface examinations, or ASME Code Section XI VT-1 examinations (including those inspections conducted on non-ASME Code components) are conducted every 10 years to detect cracking of stainless steel (SS) and aluminum components. o) Revise procedure(s) to specify that surface examinations, or ASME Code Section XI VT-1 examinations, are conducted on 20% of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of 1-foot length sections and components	

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			can be used to meet the recommended extent of 25 inspections. The provisions of GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to conduct inspections in a more severe environment and combination of air environments may be incorporated for these inspections. p) Revise procedure(s) to specify alternative methods for detecting moisture inside piping insulation (such as thermography, neutron backscatter devices, and moisture meters) are to be used for inspecting piping jacketing that is not installed in accordance with plant-specific procedures (such as no minimum overlap, wrong location of seams, etc.). q) Revise procedure(s) to include the following information: • Component surfaces that are insulated and exposed to condensation (because the in-scope component is operated below the dew point), and insulated outdoor components, are periodically inspected every 10 years during the SPEO. • For all outdoor components and any indoor components exposed to condensation (because the in-scope component is operated below the dew point), inspections are conducted of each material type (e.g., steel, SS, copper alloy, aluminum) and environment (e.g., air outdoor, air accompanied by leakage) where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, significant moisture can accumulate under insulation during high humidity seasons, even in conditioned air. A minimum of 20% of the in-scope piping length, or 20% of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Alternatively, any combination of a minimum of 25 1-foot axial length sections and components for each material type is inspected. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the	

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			component), and lowest design margin. Inspections for cracking due to SCC in aluminum components need not be conducted if it has been determined that SCC is not an applicable aging effect. r) Revise procedure(s) to specify that: • Visual inspection will identify direct indicators of loss of material due to wear to include dimension change, scuffing, and, for flexible polymeric materials with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. • Visual inspection of elastomers and flexible polymers will identify indirect indicators of elastomer and flexible polymer hardening or loss of strength, including the presence of surface cracking, crazing, discoloration, and, for elastomers with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. • Visual inspections will cover 100% of accessible component surfaces. • Manual or physical manipulation can be used to augment visual inspection to confirm the absence of hardening or loss of strength for elastomers and flexible polymeric materials (e.g., heating, ventilation, and air conditioning flexible connectors) where appropriate, and the sample size for manipulation is at least 10% of available surface area. s) Revise procedure(s) to formalize sampling-based inspections. The results of sampling-based inspections will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain intended functions of the components throughout the SPEO based on the projected rate and extent of degradation. t) The AMP owner will interface with the fleet corrosion monitoring action program to identify problem areas and track resolution of deficiencies. u) Revise procedure(s) to add an evaluation to project the degree of observed degradation to the end of the SPEO or the next scheduled inspection, whichever is shorter.	

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			v) Revise procedure(s) to specify where practical, acceptance criteria are quantitative (e.g., minimum wall thickness, percent shrinkage allowed in an elastomeric seal). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. Where qualitative acceptance criteria are used, the criteria are clear enough to reasonably ensure that a singular decision is derived based on the observed condition of the systems, structures, and components (e.g. cracks are absent in rigid polymers, the flexibility of an elastomeric sealant is sufficient to ensure that it will properly adhere to surface). w) Revise procedure(s) to include guidance from EPRI TR-1007933 “Aging Assessment Field Guide and TR-1009743 “Aging Identification and Assessment Checklist” on the evaluation of materials and criteria for their acceptance when performing visual/tactile inspections. x) Revise procedure(s) to specify that additional inspections will be performed if any sampling-based inspections to detect cracking in aluminum and stainless steel components do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. The additional inspections will be completed within the interval (e.g., 10-year inspection interval) in which the original inspection was conducted. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent-of-cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2.	

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28	Flux Thimble Tube Inspection (16.2.2.24)	XI.M37	Continue the existing PBN Flux Thimble Tube Inspection AMP, including enhancement to: a) Remove from service the flux thimble tubes that cannot be inspected over the tube length yet are subject to wear due to restriction or other defects but cannot be shown by analysis to be satisfactory for continued service. This maintains the integrity of the RCS pressure boundary.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032
29	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (16.2.2.25)	XI.M38	Implement the new PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP. The following items shall be included in the new AMP: a) Perform an internal inspection of the Unit 1 RHR flow control valves within the next two refueling outages. The need for additional or periodic inspections will be determined based on the inspection results.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032 Note that the U1 RHR flow control valve inspection is to be completed within the next two refueling outages (no later than 2023).
30	Lubricating Oil Analysis (16.2.2.26)	XI.M39	Continue the existing PBN Lubricating Oil Analysis AMP, including enhancement to: a) Manage aging effects associated with in-scope piping and piping components exposed to an environment of hydraulic oil. b) Manage aging effects associated with reactor coolant pump system components that are exposed to an environment of lubricating oil. In addition, manage other in-scope components exposed to lubricating oil environments and subject to aging management review.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032

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			c) Maintain contaminants in the in-scope lubricating oil and hydraulic oil systems within acceptable limits through periodic sampling and testing for moisture and particle count in accordance with industry standards. All lubricating oil analysis results will be reviewed and trended to determine if alert limits have been reached or exceeded, as well as, if there are any unusual or adverse trends associated with the oil sample. d) Sampling and testing of old oil will be performed following periodic oil changes, or on a schedule consistent with equipment manufacturer's recommendations or industry standards [e.g., American Society of Testing Materials (ASTM) D 6224 02]. Plant specific operating experience associated with lubricating oil systems may also be used to adjust the schedule for periodic sampling and testing, when justified by prior sampling results. e) For hydraulic fluids, if the fluid is replaced based on a periodicity recommended by the fluid manufacturer, equipment vendor, or plant-specific documents, testing is not required. Alternatively, the hydraulic fluid will be tested for water content if the oil is not clear or bright, and for particulate count. f) Compare the particulate count of the samples with acceptance criteria for particulates. The acceptance criteria for water and particle concentration within the oil must not exceed limits based on equipment manufacturer's recommendations or industry standards. If an acceptance criteria limit is reached or exceeded, actions to address the condition are to be taken. Corrective actions may include increased monitoring, corrective maintenance, further laboratory analysis, and engineering evaluation of the specified lubricating oil system. g) Phase-separated water in any amount is not acceptable. If phase-separated water is identified in the sample, then corrective actions are to be initiated to identify the source and correct the issue (e.g., repair/replace component or modify operating conditions).	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
31	Buried and Underground Piping and Tanks (16.2.2.27)	XI.M41	Continue the existing PBN Buried and Underground Piping and Tanks AMP, including enhancement to: a) Ensure that the cathodic protection system will meet the requirements of GALL-SLR Section XI.M41, including the polarized potential criteria of NUREG 2191. PBN takes an exception to the NUREG-2191 requirement of meeting the cathodic protection requirements of NACE SP0169-2007. Instead, PBN is committed to meeting the cathodic protection system requirements of NACE SP0169-2013 (with the exception of Section 6, “Criteria and Other Considerations for Cathodic Protection”). The information from NACE SP0169-2007 shall be used instead of NACE SP0169-2013 for Section 6. Additionally, the cathodic protection system shall also include annual system monitoring. b) Ensure that new or replaced backfill shall meet the requirements of NACE SP0169-2007 Section 5.2.3 or NACE RP0285-2002, Section 3.6. c) Perform visual inspection of the external surfaces of controlled low strength material backfill, where such backfill is used, to detect potential cracks that could admit groundwater to the surface of the component. d) Measure wall thickness with volumetric examination and pit depth gages or calipers using techniques that have been determined to be effective for the material, environment, and conditions (e.g., remote methods) during the examination and are capable of quantifying general wall thickness and the depth of pits. e) Inspect for cracking in steel utilizing a method that has been determined to be capable of detecting cracking. Coatings that: (a) are intact, well-adhered, and otherwise sound for the remaining inspection interval; and (b) exhibit small blisters that are few in number and completely surrounded by sound coating bonded to the substrate do not have to be removed. Inspections for cracking are conducted to assess the impact of cracks on the pressure boundary function of the component.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032 Implement the AMP and start the one-time and 10-year interval inspections no earlier than 10 years prior to the SPEO.

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			f) Monitor the pipe-to-soil potential and the cathodic protection current for steel piping and tanks in contact with soil to determine the effectiveness of cathodic protection systems. g) Perform inspections of buried and underground piping and tanks will be conducted in accordance with NUREG-2191 Table XI.M41-2 Category C steel. The inspections will be distributed evenly among the units. Since PBN is a two-unit site, the inspection quantities are 50% greater than NUREG-2191 Table XI.M41-2 and are rounded up to the nearest whole inspection. Thus, the number of inspections for each 10-year inspection period, commencing 10 years prior to the SPEO and continuing during the SPEO, is as follows: • Buried Piping: The smaller of 0.5% of the piping length or two 10-foot segments. • Buried Tank: One inspection for tank T-072. • Underground Tanks: Monitor annular space of double walled tanks T-175A and T-175B for leakage. When the inspections for a given material type is based on percentage of length and results in an inspection quantity of less than 10 feet, then 10 feet of piping is inspected. If the entire run of piping of that material type is less than 10 feet in total length, then the entire run of piping is inspected. h) Perform surface and/or volumetric nondestructive testing if evidence of wall loss beyond minor surface scale is observed. i) Include the guidance for piping inspection location selection as follows: (a) a risk ranking system software incorporates inputs that include coating type, coating condition, cathodic protection efficacy, backfill characteristics, soil resistivity, pipe contents, and pipe function; (b) opportunistic examinations of nonleaking pipes may be credited toward examinations if the location selection criteria are met; and (c) the use of guided wave ultrasonic examinations may not be substituted for the required inspections.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			j) Select an alternative to visual examination of piping from NUREG-2191 pages XI.M41-9 and XI.M41-10. k) Perform the examinations of the buried tank T-072 from either the external surface of the tank using visual techniques or from the internal surface of the tank using volumetric techniques A minimum of 25% of the buried surface is examined. This area includes at least some of both the top and bottom of the tank. If the tank is inspected internally by volumetric methods, the method must be capable of determining tank wall thickness and general and pitting corrosion and qualified at PBN to identify loss of material that does not meet acceptance criteria. The double wall tanks, T-175A and T-175B shall be examined by monitoring the annular space for leakage. l) Utilize the potential difference and current measurements from the periodic cathodic protection testing for trending. m) Perform trending of wall thickness measurements and project to the next scheduled inspection. n) Evaluate inspection and test results against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the component intended functions throughout the SPEO based on the projected rate and extent of degradation. o) Utilize an acceptance criterion of no evidence of coating degradation. Otherwise have the type and extent of coating degradation evaluated as insignificant by an individual: (a) possessing a NACE Coating Inspector Program Level 2 or 3 inspector qualification; (b) who has completed the Electric Power Research Institute Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course; or (c) a coatings specialist qualified in accordance with an ASTM standard endorsed in Regulatory Guide 1.54, Revision 2, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.”	

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			p) Ensure projected wall thickness continues to meet minimum wall thickness requirements through the end of the SPEO. q) Evaluate all backfill caused damage to the respective component coatings or the surface of the component. r) Perform corrective action on cracks in cementitious backfill that could admit groundwater to the surface of the component. s) Utilize the Table XI.M41-3 acceptance criteria for pipe-to-soil potential when using a saturated copper/copper sulfate (CSE). t) Perform an extent of condition evaluation when damage to the coating has been evaluated as significant and the damage was caused by nonconforming backfill. u) Evaluate the coated and uncoated metallic piping and tanks that show evidence of corrosion to ensure that the minimum wall thickness is maintained throughout the SPEO. This may include different values for large area minimum wall thickness and local area wall thickness. If the wall thickness extrapolated to the end of the SPEO meets minimum wall thickness requirements, the NUREG-2191 Section XI.M41 recommendations for expansion of sample size do not apply. v) Expand the sample size when the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material is extrapolated to the end of the SPEO in the following manner: The number of inspections within the affected piping categories are doubled or increased by five, whichever is smaller. If the acceptance criteria are not met in any of the expanded samples, an analysis is conducted to determine the extent of condition and extent of cause. The number of follow-on inspections is determined based on the extent of condition and extent of cause. The timing of the additional examinations is based on the severity of the degradation identified and is commensurate with the consequences of a leak or loss of function. However, in all cases, the expanded sample inspection is completed within the 10 year interval in which the original inspection was conducted	

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			or, if identified in the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval. These additional inspections conducted during the 4 years following the end of an inspection interval cannot also be credited towards the number of required inspections for the following 10-year interval. The number of inspections may be limited by the extent of piping or tanks subject to the observed degradation mechanism. The expansion of sample inspections may be halted in a piping system or portion of system that will be replaced within the 10-year interval in which the inspections were conducted or, if identified in the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval.	
32	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (16.2.2.28)	XI.M42	Implement the new PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP and complete the initial inspections.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032 Perform the baseline inspections no earlier than 10 years or no later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO.
33	ASME Section XI, Subsection IWE (16.2.2.29)	XI.S1	Continue the existing PBN ASME Section XI, Subsection IWE AMP, including enhancement to: a) Augment existing procedures to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,”	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO, i.e.:

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			EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," and the additional recommendations of NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants."; b) Augment existing procedures to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490 bolts, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts," will be used. c) Augment existing procedures to specify that pressure retaining bolting is inspected for loosening and material condition affecting leak tightness or structural integrity. d) Augment existing procedures to implement periodic supplemental surface examinations (or other appropriate examination/evaluation methods) at intervals no greater than other IWE inspections to detect cracking due to cyclic loading of non-piping penetrations (hatches, electrical penetrations, etc.). e) Augment existing procedures to implement supplemental one-time inspections, performed by qualified personnel using methods capable of detecting cracking due to SCC, comprising (a) a representative sample (two) of the stainless steel penetrations or dissimilar metal welds associated with high-temperature (temperatures above 140°F) stainless steel piping systems in frequent use on each unit; and (b) the stainless steel fuel transfer tube on each unit. If SCC is detected as a result of the supplemental one-time inspections, additional inspections will be conducted in accordance with the site's corrective action process. f) Augment existing procedures to implement a one-time supplemental volumetric inspection of metal liner surfaces that samples randomly selected as well as focused locations susceptible to loss of thickness due to corrosion from the concrete side if triggered by plant-specific OE	PBN1: 04/05/30 PBN2: 09/08/32 Start the one-time inspections for cracking due to SCC no earlier than five years prior to the SPEO.

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			identified through code inspections after the date of issuance of the first renewed license for each unit.	
34	ASME Section XI, Subsection IWL (16.2.2.30)	XI.S2	Continue the existing PBN ASME Section XI, Subsection IWL AMP, including enhancement to: a) Augment existing procedures to specify that inspection results be compared to previous results to identify changes from prior inspections, and that quantitative measurements and qualitative information are recorded and trended for applicable parameters monitored or inspected. b) Augment existing procedures to specify that inspection results be compared to previous results to determine if degradation is passive for application of second-tier acceptance criteria as specified in ACI 349.3R.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32
35	ASME Section XI, Subsection IWF (16.2.2.31)	XI.S3	Continue the existing PBN ASME Section XI, Subsection IWF AMP, including enhancement to: a) Augment existing procedures to evaluate the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. b) Augment existing procedures to include vibration isolation elements of ASME Section XI Class 1, 2, and 3 supports within the ISI Program scope. c) Augment existing procedures to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” EPRI TR-104213, “Bolted Joint Maintenance & Application Guide,” and the additional recommendations of NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation of Failure in Nuclear Power Plants.”	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32 Start the one-time inspections no earlier than five years prior to the SPEO.

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			d) Augment existing procedures to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490 bolts, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts," will be used. e) Augment existing procedures to specify that bolting within the scope of this program is inspected for loss of integrity of bolted connections due to self-loosening. f) Augment existing procedures to specify that elastomeric or polymeric vibration isolation elements are monitored for cracking, loss of material, and hardening. g) Perform and document a one-time inspection of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation. h) Augment existing procedures to include tactile inspection (feeling, prodding) of elastomeric vibration isolation elements to detect hardening if the vibration isolation function is suspect. i) Augment existing procedures to specify that, for NSSS component supports, high-strength bolting greater than one inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT3 examination. In each 10-year period during the SPEO, a representative sample of bolts will be inspected. The sample will be 20% of the population (for a material / environment combination) up to a maximum of 25 bolts. j) Augment existing procedures to increase or modify the component support inspection population when a component is repaired to as-new	

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			condition by including another support that is representative of the remaining population of supports that were not repaired. k) Augment existing procedures to specify that the following conditions are also unacceptable: loss of material due to corrosion or wear; debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support; cracking or sheared bolts, including high-strength bolts, and anchors; loss of material, cracking, and hardening of elastomeric or polymeric vibration isolation elements that could reduce the vibration isolation function; and cracks.	
36	10 CFR Part 50, Appendix J (16.2.2.32)	XI.S4	Continue the existing PBN 10 CFR Part 50, Appendix J AMP	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32
37	Masonry Walls (16.2.2.33)	XI.S5	Continue the existing PBN Masonry Walls AMP, including enhancement to: a) Revise implementing procedures to also monitor and inspect for spalling, scaling, shrinkage and/or separation as well as loss of material at the mortar joints, and gaps between the supports and masonry walls that could potentially impact the intended function or potentially invalidate its evaluation basis. b) Revise implementing procedures to also include specific monitoring, measurement, and trending of widths and lengths of cracks and of gaps between supports and masonry walls. c) Revise implementing procedures to also include specific assessment of the acceptability of crack widths and lengths and gaps between supports and masonry walls.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32

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38	Structures Monitoring (16.2.2.34)	XI.S6	Continue the existing PBN Structures Monitoring AMP, including enhancement to: a) Revise inspection procedures to include guidance and acceptance criteria on inspections of stainless steel and aluminum components for pitting and crevice corrosion, and evidence of cracking due to SCC. Perform an evaluation if stainless steel or aluminum surfaces exhibit evidence of SCC, pitting, or crevice corrosion. b) Revise implementing procedures to address preventive actions to ensure proper selection and storage of high strength bolting in accordance with Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts”. c) Revise inspection procedures to additionally inspect for the following items: • Increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation in concrete structures. • Loss of material and loss of strength for elastomers. • Pitting and crevice corrosion, and evidence of cracking due to SCC for stainless steel and aluminum components • Confirmation of the absence of water in-leakage through concrete. d) Revise inspection procedures to include guidance on MEB inspection for loss of material (external bus duct enclosure surfaces and structural supports) and elastomer degradation (exterior housing gaskets, boots, and sealants). e) Clarify that if ground water leakage is identified then engineering evaluation, more frequent inspections, or destructive testing of affected concrete (to validate properties and determine pH) are required. f) Revise inspection procedure to include the following acceptance criteria: • For Elastomers: No loss of material and no indications of loss of strength such as unacceptable surface cracking, crazing, scuffing,	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, or hardening. • For Bolting and Fasteners: Loose bolts and nuts are not acceptable unless accepted by engineering evaluation. • For Structural Sealants: Observed loss of material, cracking, and hardening will not result in loss of sealing.	
39	Water-Control Structures (16.2.2.35)	XI.S7	Continue the existing PBN Water-Control Structures AMP, including enhancement to: a) Revise the implementing procedure to also monitor concrete to confirm the absence of water leakage. b) Revise the implementing procedure to include provisions for special inspections immediately following the occurrence of significant natural phenomena, such as large floods, earthquakes, tornadoes, or intense local rainfalls. c) Revise the implementing procedure to clarify that if water leakage is identified, then engineering evaluation, more frequent inspections, or destructive testing of affected concrete (to validate properties and determine pH) are required. d) Revise the implementing procedure to indicate that loose bolts and nuts are unacceptable unless they are determined to be acceptable by engineering evaluation or subject to corrective actions	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32
40	Protective Coating Monitoring and Maintenance (16.2.2.36)	XI.S8	Continue the existing PBN Protective Coating Monitoring and Maintenance AMP, including enhancements to: a) Revise implementing procedures to specify that follow-up inspections be performed by individuals trained and certified in the applicable reference standards of ASTM Guide D5498. b) Revise implementing procedures to ensure a thorough visual inspection shall be carried out on all coatings near sumps or screens associated with the ECCS.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32

Table 16-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			c) Revise implementing procedures to include coating specifications in the list of pre-inspection documentation available to the inspection team. d) Revise the implementing procedures to reference Position C.4 of Regulatory Guide 1.54 Rev. 3 for Maintenance of Service Level I Coatings.	
41	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (16.2.2.37)	XI.E1	Continue the existing PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP including enhancement to: a) Review plant-specific OE for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation during the original PEO. Evaluate to confirm that the dispositioned corrective actions continue to support in-scope cable and connection intended functions during the SPEO. b) If cable testing is deemed necessary, utilize sampling methodology consistent with guidance of Section XI.E1 of NUREG-2191.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32
42	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (16.2.2.38)	XI.E2	Continue the existing PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32
43	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to	XI.E3A	Continue the existing PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32

Table 16-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
	10 CFR 50.49 Environmental Qualification Requirements (16.2.2.39)			
44	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (16.2.2.40)	XI.E3B	Implement the new PBN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32
45	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (16.2.2.41)	XI.E3C	Implement the new PBN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32
46	Metal Enclosed Bus (16.2.2.42)	XI.E4	Implement the new PBN Metal Enclosed Bus AMP.	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32

Table 16-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
47	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (16.2.2.43)	XI.E6	Implement the new PBN Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/2030 PBN2: 09/08/2032
48	High-Voltage Insulators (16.2.2.44)	XI.E7	Implement the new PBN High-Voltage Insulators AMP.	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32
49	Quality Assurance Program (16.1.3)	Appendix A	Continue the existing NEE QA Program at PBN.	Ongoing
50	Operating Experience Program (16.1.4)	Appendix B	Continue the existing PBN OE Program	Ongoing
51	Containment Structure and Internal Structural Components Aging Management Review	N/A	Follow the ongoing industry efforts that are clarifying the effects of irradiation on concrete and RV support steel and corresponding aging management recommendations, including: a) Ensure their applicability to the PBN Unit 1 and Unit 2 primary shield wall and associated reactor vessel supports; b) Update design calculations, as appropriate, and; c) Develop an informed site-specific program, if needed.	No later than 6 months prior to the SPEO, i.e.: PBN1: 04/05/30 PBN2: 09/08/32

16.5. References

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112. Westinghouse, WCAP-15666-A, “Extension of Reactor Coolant Pump Motor Flywheel Examination,” October 2003 (ADAMS Accession No. ML18303A413).

113. Westinghouse, WCAP-15988-NP, Revision 2, “Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors,” Westinghouse Electric Company, June 2012.

114. Westinghouse, WCAP-16083-NP-A, Revision 0, “Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry,” Westinghouse Electric Company, May 2006.

115. Westinghouse, WCAP-18124-NP-A, Revision 0, “Fluence Determination with RAPTOR-M3G and FERRET,” July 2018.

116. Westinghouse, WCAP-18555-NP, Rev 0, “Point Beach Units 1 and 2 Time-Limited Aging Analyses (TLAAs) on Reactor Vessel Integrity (RVI) for Subsequent License Renewal (SLR),” July 2020.

117. a. Westinghouse, PWROG-17033-P-A, Revision 1, “Update for Subsequent License Renewal: WCAP-13045, “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Steams,” November 2019.

     b. Westinghouse, PWROG-17033-NP-A, Revision 1, “Update for Subsequent License Renewal: WCAP-13045, “Compliance to ASME Code Case N-481 of Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Steams,” November 2019.

Appendix A
USFAR Changes

This section provides a markup of the Point Beach Units 1 and 2 UFSAR delineating UFSAR changes that will be required for subsequent license renewal.

UFSAR CHAPTER 1
CHANGES

Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels). In addition to the required tension and Charpy impact specimens, the Point Beach material surveillance program also includes fracture toughness specimens. Additional samples of reactor vessel plate and forging materials have been retained and catalogued and are available for future testing, as needed.

The measured shift in RT_{NDT} of the beltline region materials with irradiation are used to establish plant specific values of shift in accordance with the regulatory guidance of NRC Regulatory Guide 1.99, Rev. 2, "Radiation Embrittlement of Reactor Vessel Materials." Where credible data is not available for specific weld or base metals, Regulatory Guide 1.99 provides trend curves for the shift in RT_{NDT} based on fast neutron fluence, material form (base or weld metal), and the weight-percent of copper and nickel of the reactor vessel steel. A margin term is also added to the shift to obtain conservative, upper-bound values of the adjusted RT_{NDT} for use in the evaluations required by Appendix G to 10 CFR 50. See Section 15.4.1 for the discussion of the fracture toughness methodology evaluation reviewed and approved by the NRC for License Renewal for Unit 2~~.~~ (NRC SE dated 12/2005, NUREG-1839). See Section 16.3.2 for the discussion of the fracture toughness methodology evaluation reviewed and approved by the NRC for Subsequent License Renewal for Unit 2 ([TBD]).

As a supplement to the plant specific material surveillance program for Point Beach, additional surveillance data is available through participation in the Babcock & Wilcox Owners Group Master Integrated Reactor Vessel Surveillance Program. This integrated program includes weld metals used in the construction of the Point Beach reactor vessels that are not included in the plant specific surveillance program for Point Beach.

Reference Sections:

Section Title	Chapter
REACTOR COOLANT SYSTEM (RCS)	4.1
RCS SYSTEM DESIGN AND OPERATION	4.0
SYSTEM DESIGN EVALUATION	4.3
VESSEL RT_{NDT}	4.0

1.3.7 ENGINEERED SAFETY FEATURES (GDC 37 - GDC 65)

The design, fabrication, testing, and inspection of the core, reactor coolant pressure boundary, and their protection systems give assurance of safe and reliable operation under all anticipated normal, transient, and accident conditions.

However, engineered safety features are provided in the facility to back up the safety provided by these components. These engineered safety features have been designed to cope with any size reactor coolant pipe break up to and including the circumferential rupture of any pipe assuming unobstructed discharge from both ends, and to cope with any steam or feedwater line break up to and including the main steam or feedwater headers. The concurrent, total loss of all offsite power is assumed with these accidents.

The release of fission products from the reactor fuel is limited by the Safety Injection System which, by cooling the core and limiting the fuel cladding temperature, keeps the fuel in place and substantially intact with its heat transfer geometry preserved and limits the metal-water reaction to an insignificant amount.

1.4 QUALITY ASSURANCE PROGRAM

NextEra Energy Point Beach, LLC nuclear plant operational and support activities are conducted under NextEra Energy Quality Assurance Topical Report (QATR), FPL-1. FPL-1 is the top-level policy document that establishes the manner in which quality is to be achieved and presents NextEra Energy's overall philosophy regarding achievement and assurance of quality. The QATR responds to and satisfies the requirements of Appendix B of 10 CFR Part 50 (Reference 1).

In addition to the commitments identified in the QATR, Point Beach also has the following commitment to Regulatory Guide (RG) 1.54 dated June 1973:

PBNP is committed to follow the position of RG 1.54 (1973), Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants, which endorses and supplements ANSI N101.4-1972, Quality Assurance for Protective Coatings Applied to Nuclear Facilities, for activities that affect quality and occur during the operational phase, and that are comparable in nature and extent to related activities occurring during construction. Procedures and programmatic controls ensure that the applicable requirements for the procurement, application, inspection, and maintenance of Service Level I coatings in containment are implemented. The surface preparation, application and surveillance during installation of Service Level I coatings used for new applications or repair/replacement activities inside containment meet the applicable portions of RG 1.54 and ANSI N101.4-1972.

Point Beach was built and licensed prior to RG 1.54 being issued, and, as such, does not conform fully to all aspects of ANSI N101.4-1972 and RG 1.54. The original coatings inside containment were applied without the documentation and/or testing necessary to be considered Service Level I coatings. These original coatings are considered acceptable based on WCAP-7198-L and the evaluation in Section 5.6.2.4.

Relatively small amount of coatings applied by vendors on supplied equipment, miscellaneous structural supports, and small areas of touch-up on qualified Service Level I coatings may not be Service Level I coatings. With the exception of isolated minor touch-up repairs (i.e., less than 1 ft^2), all coating repairs, maintenance, and applications inside containment are required to be performed with Service Level I coatings.

For details of the Quality Assurance requirements for the Aging Management Programs implemented in accordance with 10 CFR 54, see Chapter 15 for the period of extended operation. Records necessary to document compliance with the provisions of 10 CFR 54 will be retained for the term of the renewed operating license (Reference 2).

For details of the Quality Assurance requirements for the Aging Management Programs implemented in accordance with 10 CFR 54, see Chapter 16 for the subsequent period of extended operation. Records necessary to document compliance with the provisions of 10 CFR 54 will be retained for the term of the renewed operating license (Reference 3).

1.4.1 REFERENCES

1. FPL letter to the NRC; "Quality Assurance Topical Report (QATR FPL-1), Revisions 1 and 2," dated June 27, 2008.

2. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, Docket Nos. 50-266 and 50-301, dated December 2005.

3. [TBD]

1.5 FACILITY SAFETY CONCLUSIONS

The safety of the public and plant operating personnel and reliability of plant equipment and systems have been the primary considerations in the plant design. The approach taken in fulfilling the safety consideration is three-fold. First, careful attention has been given to the design to prevent the release of radioactivity to the environment under conditions which could be hazardous to the health and safety of the public. Second, the plant has been designed so as to provide adequate protection for plant personnel wherever a potential radiation hazard exists. Third, reactor systems and controls have been designed with a great degree of redundancy and fail-safe characteristics.

Based on the over-all design of the plant including its safety features, the analyses of the possible incidents and of hypothetical accidents, and the operational history of the Point Beach Nuclear Plant, it is concluded that Point Beach Nuclear Plant Units 1 and 2 can be operated without undue hazard to the health and safety of the public.

On April 16, 1970, by letter to the Chairman of the U.S. Atomic Energy Commission, the Advisory Committee on Reactor Safeguards (ACRS) reported its completed review of the operating license application for Point Beach Nuclear Plant Units 1 and 2 (Reference 1). The ACRS concluded that subject to satisfactory completion of construction and pre-operational testing, and given due regard for those items mentioned in the letter, Point Beach Nuclear Plant Units 1 and 2 can be operated at power levels up to 1518.5 MWt for each unit without undue risk to the health and safety of the public. Similarly, the U.S. Atomic Energy Commission, in its Safety Evaluation Report for the Point Beach Nuclear Plant Units 1 and 2 dated July 15, 1970 (Reference 2), concluded that, "There is reasonable assurance (i) that the activities authorized by the operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the regulations of the Commission set forth in 10 CFR Chapter 1." On 11/29/2002 a License Amendment Request, increasing Thermal Power to 1540 MWt, was approved by the NRC (Reference 3). The basis of the change was the implementation of a 10 CFR 50, Appendix K uprate based on a reduction in power measurement uncertainty.

In December, 2005, the NRC issued NUREG-1839, "Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2." Based on the license renewal application, the NRC staff concluded that the requirements of 10 CFR 54.29(a) had been met and that all open items and confirmatory items have been resolved. The renewed licenses are applicable for 20 years beyond the expiration date of midnight, October 5, 2010 for Unit 1 and midnight, March 8, 2013 for Unit 2.

On May 3, 2011, the NRC approved a License Amendment Request increasing core thermal power to 1800 MWt (Reference 4). This power increase and associated changes to the operating license, Technical Specifications, and licensing basis is defined as an Extended Power Uprate (EPU).

In [month, year], the NRC issued [SER title]. Based on the subsequent license renewal application, the NRC staff concluded that the requirements of 10 CFR 54.29(a) had been met and that all open items and confirmatory items have been resolved. The subsequent renewed licenses are applicable for 20 years beyond the expiration date of midnight, October 5, 2030 for Unit 1 and midnight, March 8, 2033 for Unit 2. [Confirm these dates.]

1.5.1 REFERENCES

1. Advisory Committee on Reactor Safeguards letter to the U.S. Atomic Energy Commission, dated April 16, 1970.

UFSAR CHAPTER 4
CHANGES

To provide the necessary high degree of integrity for the equipment in the Reactor Coolant System, the transient conditions selected for equipment fatigue evaluation are based on a conservative estimate of the magnitude and frequency of the temperature and pressure transients resulting from normal operation, and normal and abnormal load transients. To a large extent, the specific transient operating condition considered for equipment fatigue analyses are based upon engineering judgment and experience. Those transients are chosen which are representative of transients to be expected during plant operation and which are sufficiently severe or frequent to be of possible significance to component cyclic behavior.

Clearly, it is difficult to discuss in absolute terms, the transients that the plant will actually experience during the ~~60~~ 80-year~~s~~ operating life. (~~NRC SE dated 12/2005, NUREG -1839~~[TBD]) For clarity, however, each transient condition is discussed in order to make clear the nature and basis for the various transients.

Heatup and Cooldown

The heatup or cooldown cases are conservatively represented by a continuous operation performed at a uniform temperature rate of 100°F per hour. For these cases, the heatup occurs from ambient to the no-load temperature and pressure condition and the cooldown represents the reverse situation. In actual practice, the rate of temperature change of 100°F per hour will not be attained because of other limitations such as:

1. Material NDT considerations which may establish maximum permissible temperature rate of change, as a function of plant pressure and temperature, which are below the design rate of 100°F per hour.

2. Slower initial heatup rates attainable from pump energy and pressurizer heaters only.

3. Interruptions in the heatup and cooldown cycles due to such factors as drawing a pressurizer steam bubble, required testing, rod withdrawal, sampling, water chemistry, and gas adjustments.

4. Design and operating restrictions associated with reactor critical conditions.

The number of complete heatup and cooldown operations is specified at 200 times for the ~~60~~80-year plant design life. For the ideal plant, only one heatup and one cooldown would occur per fuel cycle, i.e., the period between refuelings. (~~NRC SE dated 12/2005, NUREG -1839~~[TBD]) In practice, experience to date indicates that, during the first year or so of operation, additional unscheduled plant cooldowns may be necessary for plant maintenance.

Unit Loading and Unloading

The unit loading and unloading cases are conservatively represented by a continuous and uniform ramp power change of 5% per minute between no load and full load. The reactor coolant temperature will vary with load as prescribed by the temperature control system. The number of each operation is specified in Table 4.1-8 for the ~~60~~80-year plant life. (~~NRC SE dated 12/2005, NUREG-1839~~[TBD]) In practice, the plant is generally operated at base load conditions with changes in power at a rate much less than 5% per minute.

Step Increase and Decrease of 10%

The ±10% step change in load demand is a control transient which is assumed to be a change in turbine control valve opening which might be occasioned by disturbances in the electrical network into which the plant output is tied. The reactor control system is designed to restore plant equilibrium without reactor trip following a ±10% step change in turbine load demand in the range between 15% and 100% full load, the power range for automatic reactor control. In effect, during load change conditions, the reactor control system attempts to match turbine and reactor outputs in such a manner that peak reactor coolant temperature is minimized and reactor coolant temperature is restored to its programmed set point at a sufficiently slow rate to prevent excessive pressurizer pressure change.

Following a step load decrease in turbine load, the secondary side steam pressure and temperature initially increase since the decrease in nuclear power lags behind the step decrease in turbine load. During the same increment of time, the Reactor Coolant System average temperature and pressurizer pressure also initially increase. Because of the power mismatch between the turbine and reactor, the increase in reactor coolant temperature will be ultimately reduced from its peak value to a value below its initial equilibrium value at the inception of the transient. The reactor coolant average temperature set point change is made as a function of turbine generator load as determined by first stage turbine pressure measurement. The pressurizer pressure will also decrease from its peak pressure value and follow the reactor coolant decreasing temperature trend. At some point during the decreasing pressure transient, the saturated water in the pressurizer begins to flash, which reduces the rate of pressure decrease. Subsequently, the pressurizer heaters come on to restore the plant pressure to its normal value.

Following a step load increase in turbine load, the reverse situation occurs, i.e., the secondary side steam pressure and temperature initially decrease and the reactor coolant average temperature and pressure initially decrease. The control system automatically withdraws the control rods to increase core power. The decreasing pressure transient is reversed by actuation of the pressurizer heaters and eventually the system pressure is restored to its normal value. The reactor coolant average temperature will be raised to a value above its initial equilibrium value at the beginning of the transient. The number of each operation is specified at 2000 times for the ~~60~~80-year plant life. (~~NRC SE dated 12/2005, NUREG–1839~~[TBD])

Large Step Decreases in Load

This transient applies to a step decrease in turbine load of such magnitude that the resultant rapid increase in reactor coolant average temperature and secondary side steam pressure and temperature will automatically initiate a condenser steam dump system to avert a reactor shutdown or lifting of steam generator safety valves. The number of occurrences of this transient is specified at 200 times for the ~~60~~80-year plant life. (~~NRC SE dated 12/2005, NUREG–1839~~[TBD]) The operating experience of Point Beach Nuclear Plant Units 1 and 2 also indicates that this basis is adequately conservative.

Loss-of-Load Transient

The loss-of-load transient is the most severe transient on the Reactor Coolant System. The transient applies to a step decrease in turbine load from full power occasioned by the loss-of-turbine-load without immediately initiating a reactor trip. The reactor and turbine eventually trip as a consequence of a high pressurizer pressure trip initiated by the reactor protection system. See Section 14.1.9 for loss-of-load transient analysis.

Loss-of-Flow

The loss-of-flow transient applies to a partial loss of flow accident from full power in which a reactor coolant pump is tripped out of service as a result of a loss of power to that pump. The consequences of such an accident are a reactor and turbine trip followed by automatic opening of the steam dump system and flow reversal in the affected loop. The net result of the flow reversal is a sizable reduction in the hot leg coolant temperature of the affected loop. See Section 14.1.8 for loss-of-flow transient analysis.

The number of occurrences of the above transients is generally specified at two per year of plant design life. All components in the Reactor Coolant System are designed to withstand the effects of these and other transients that result in system temperature and pressure changes.

Reactor Trip From Full Power

A reactor trip from full power may occur for a variety of causes resulting in temperature and pressure transients in the Reactor Coolant System and in the secondary side of the steam generator. This is the result of continued heat transfer from the reactor coolant in the steam generator. The transient continues until the reactor coolant and steam generator secondary side temperatures are in equilibrium at zero power conditions. A continued supply of feedwater and controlled dumping of secondary steam remove the core residual heat and prevent the steam generator safety valves from lifting. The reactor coolant temperature and pressure undergo a rapid decrease from full power values as the reactor protection system causes the control rods to move into the core.

The number of occurrences of this transient is specified at 400 times for the ~~60~~80-year plant life. (~~NRC SE dated 12/2005, NUREG -1839~~[TBD]) The tripping history of Point Beach Nuclear Plant Units 1 and 2 indicate that this basis is indeed conservative.

Feedwater Cycling at Hot Standby

Feedwater cycling can occur when the plant is being maintained at hot standby or no-load conditions. This transient assumes the intermittent addition of 32°F feedwater into the steam generator secondary side while it is in a no-load condition at 547°F. For design purposes, it is assumed that the steam generators will experience 25,000 cycles of cold feedwater introduction. Feedwater additions required during plant heatup and cooldown are assumed to by bounded by the feedwater cycling transient, with no increase in the total number of cycles.

Boron Concentration Equalization

Following a large change in boron concentration in the RCS, spray is initiated in order to equalize concentration between the loops and the pressurizer. For design purposes, it is assumed that this operation is performed once after each unit loading or unloading. The number of loading and unloading operations is defined as 11,680 occurrences during the ~~60~~80-year life of the plant. On this basis, the total number of boron concentration equalization cycles is 23,360.

Loss of Power

This transient applies to a blackout situation involving the loss of outside electrical power to the station with a reactor and turbine trip. Under these circumstances, the reactor coolant pumps are de-energized and following the coastdown of the reactor coolant pumps, natural circulation builds up in the system to some equilibrium value. This condition permits removal of core residual heat through the steam generators, which are assumed to receive feedwater from the Auxiliary Feed System (operating from diesel generator power). Steam is removed for reactor cooldown through atmospheric relief valves. The number of occurrences of this transient is assumed to be a total of 40 times in an ~~60~~80-year plant life.

Inadvertent Actuation of Auxiliary Spray

Inadvertent actuation of auxiliary spray will occur if the auxiliary spray valve is opened inadvertently during normal operation of the plant. This will introduce cold water into the pressurizer with a very sharp pressure decrease within the pressurizer, as a result. The pressure decreases rapidly to the low pressure reactor trip point, at which point it is assumed the trip is actuated. This accentuates the pressure decrease until the pressure is finally limited to the hot leg saturation pressure. At five minutes, spray is stopped and all the pressurizer heaters return the pressure to 2250 psia. For design purposes, it is assumed that there are no temperature changes in the RCS, with the exception of the pressurizer. A total of 10 occurrences of this transient are specified for a ~~60~~80-year plant life.

It should be noted that the design transient pressurizer pressure and temperature variations are considered only to occur in the pressurizer during Inadvertent Actuation of Auxiliary Spray. The design transient is not applicable to the other RCS components.

Reactor Coolant Pipe Break

This transient involves the postulated rupture of a Reactor Coolant System pipe resulting in a loss of coolant. It is conservatively assumed that the system pressure is reduced rapidly and the emergency core cooling system (ECCS) is initiated to introduce water into the reactor coolant system. Because of the rapid blowdown of coolant from the system and the conservatively large heat capacity of the metal sections of the components, it is likely that the metal will remain at or near the no-load temperature conditions when the ECCS water is introduced into the system. This hypothetical transient is not expected to occur. The postulated one-time event was included in the transient sets used to evaluate thermal and loading cycles over the ~~60~~80-year plant life.

Steam Line Break

For component evaluation, the following conservative conditions are considered:

1. The reactor is initially in a hot, zero-power subcritical condition assuming all rods in except the most reactive rod which is assumed to be stuck in its fully withdrawn position.
2. A major steam line rupture occurs and the result is a reactor and turbine trip.
3. Subsequent to the break the reactor coolant temperature cools down to 212°F.
4. The ECCS pumps restore the reactor coolant pressure to 2500 psia.

This hypothetical transient is not expected to occur. The postulated one-time event was included in the transient sets used to evaluate thermal and loading cycles over the ~~60~~80-year plant life.

For this value of Salt, an allowable number of cycles (N) is determined through design fatigue curves established for specific materials. The ratio of design cycles (n) to allowable cycles (N) gives the usage factor u_i (i = 1, 2, 3, etc.). Usage factor is determined in this manner for all transients. The cumulative usage factor is determined by summing the individual usage factors. The cumulative usage factor ($U = u_1 + u_2 + u_3 ...$) is never allowed to exceed a value of 1.0. This means that the allowable number of cycles always exceeds the design cycles. This certainty assures safety of the components against fatigue failure.

Service Life

The service life of Reactor Coolant System pressure components depends upon the end of life material radiation damage, unit operational thermal cycles, quality manufacturing standards, environmental protection, and adherence to established operating procedures.

The reactor vessel is the only component of the Reactor Coolant System which is exposed to a significant level of neutron irradiation and it is therefore the only component which is subject to any appreciable material radiation damage effects. The RT_{NDT} shift of the vessel material and welds during service due to radiation damage effects is monitored by a material surveillance program which conforms with ASTM E185-82 (Standard Practice for Conducting Surveillance Tests for Light Water Cooled Nuclear Power Reactor Vessels).

Reactor coolant system pressure and temperature limits, including those for plant heatup and cooldown, are obtained in accordance with 10 CFR 50, Appendix G by following the methods of analysis and the required margins of safety of Appendix G of ASME Code Section XI. Additional discussion of these limits is provided in Section 4.3.

To establish the service life of the Reactor Coolant System components as required by the ASME (Part III) Boiler and Pressure Vessel Code for Class A Vessels, the unit operating conditions have been established for the ~~60~~80-year life. (~~NRC SE dated 12/2005, NUREG-1839~~[TBD]) These operating conditions include the cyclic application of pressure loadings and thermal transients. The number of thermal and loading cycles used for design purposes is listed in Table 4.1-8 (Reference 10).

CODES AND CLASSIFICATIONS

All pressure containing components of the Reactor Coolant System are designed, fabricated, inspected, and tested in conformance with the applicable codes listed in Table 4.1-9. Unless stated otherwise, the version of the code which was in effect at the time the original component was ordered is applicable. The Reactor Coolant System is classified as Class I for seismic design, requiring that there will be no loss of function of such equipment in the event of the assumed maximum potential ground acceleration acting in the horizontal and vertical directions simultaneously, when combined with the primary steady state stresses.

REFERENCES

1. G.E. Lear, “Exemption from the requirements of 10 CFR 50 Appendix A, General Design Criterion 4,” dated May 6, 1986.
2. Westinghouse WCAP 14439 P Revision 2, “Technical Justification for Eliminating Large Primary Loop Pipe Units 1 and 2 for the Power Uprate and License Renewal Program.” (Proprietary)

Table 4.1-8 THERMAL AND LOADING CYCLES

Transient Condition	Design Cycles*
1. Plant heatup at 100°F per hour	200
2. Plant cooldown at 100°F per hour	200
3. Plant loading at 5% of full power per minute	~~18,300~~11,600(2) (~~for all components~~ except for ~~pressurizer and~~ reactor vessel internal baffle bolts which are ~~11,600~~2,485 ~~and 2,485 respectively~~)
4. Plant unloading at 5% of full power per minute	~~18,300~~11,600(2) (~~for all components~~ except ~~pressurizer and~~ reactor vessel internal baffle bolts which are ~~11,600~~2,485 ~~and 2,485 respectively~~)
5. Step load increase of 10% of full power (but not to exceed full power)	2,000 (1)
6. Step load decrease of 10% of full power	2,000 (1)
7. Step load decrease of 50% of full power	200 (1)
8. Steady State Fluctuations	
Initial Fluctuations (+3°F and + 25 psi)	1.5×10^5
Random Fluctuations (+0.5°F and + 6 psi)	5×10^6
9. Feedwater cycling at hot standby	2000 Reactor Vessel 25,000 (Unit 1 - other components) 10,000 (Unit 2 - other components)
10. Boron concentration equilibrium	23,360
11. Loss of Load	80 (1)
12. Loss of Power	40 (1)
13. Loss of flow in one loop	80 (1)
14. Reactor trip and attendant temperature transients	400 (1)
15. Inadvertent auxiliary spray	10
16. Reactor Coolant Pipe Break	1
17. Steam Line Break	1
18. Turbine roll test	10
19. Hydrostatic test, pressure 3110 psig temperature-cold	5 (preoperational)
20. Hydrostatic test, pressure 2485 psig temperature 400°F	94 (post-operational)
21. Primary to secondary leak test (2250) psig	27
22. Secondary to primary leak test	128

* Estimated for equipment design purposes (~~60~~80-year life) and not intended to be an accurate representation of actual transients or to reflect actual operating experience. These cycles also assume a power uprate. (~~NRC SE dated 12/2005, NUREG 1839~~[TBD])

(1) For Reactor Vessel Internal baffle bolts, the total of these 7 transients is 750.

(2) Specific 80-year allowable cycles are 8000 with the exception of the following values for specific RCS components due to environmentally-assisted fatigue (EAF) values:
  - (a) CRDM upper latch housings are limited to 2700 loading and unloading cycles at 5%/min
  - (b) Vessel flanges are limited to 5000 loading and unloading cycles at 5%/min
  - (c) The fatigue crack growth (FCG) analysis of longitudinal flaws in reactor coolant loop cast austenitic stainless steel piping components utilizes a limit of 3000 loading and unloading cycles at 5%/min

Precautionary measures, taken to preclude missile formation from primary coolant pump components, assure that the pumps will not produce missiles under any anticipated accident condition. The primary coolant pumps run at 1189 rpm and the motors are designed in accordance with NEMA standards for operation at a maximum speed of 125% of rated speed. Each component of the primary pumps has been analyzed for missile generation. Any fragments would be contained by the heavy stator. The same conclusion applies to the impeller because the small fragments that might be ejected would be contained by the heavy casing.

The primary coolant pump flywheels are shown in Figure 4.2-8. As for the pump motors, the most adverse operating condition of the flywheels is the loss-of-load situation. The following conservative design-operation conditions preclude missile production by the pump flywheels. The wheels are fabricated from rolled, vacuum-degassed, steel plates. The material is ASTM A533 Grade B Class 1. (Reference 11) Flywheel blanks are flame-cut from the plate, with allowance for exclusion of flame affected metal. A minimum of three Charpy tests are made from each plate parallel and normal to the rolling direction to determine that each blank satisfies design requirements. An NDTT less than +10°F is specified. The finished flywheels are subjected to 100% volumetric ultrasonic inspection. The finished machined bores are also subjected to magnetic particle or liquid penetrant examination.

These design fabrication techniques yield flywheels with primary stress at operating speed (shown in Figure 4.2-9) less than 50% of the minimum specified material yield strength at room temperature (100 to 150°F). Bursting speed of the flywheels has been calculated on the basis of Griffith-Irwin's results (Reference 6), to be 3900 rpm, more than three times the operating speed. A fracture mechanics evaluation was made on the reactor coolant pump flywheel. This evaluation considered the following assumptions:

1. Maximum tangential stress at an assumed overspeed of 125%.
2. A crack through the thickness of the flywheel at the bore.
3. ~~400~~500 cycles of startup operation in ~~40~~80 years.

Using critical stress intensity factors and crack growth data attained on flywheel material, the critical crack size for failure was greater than 17 inches radially and the crack growth data was 0.030 in. to 0.060 in. per 1000 cycles. Ultrasonic examination techniques which are capable of detecting and sizing flaws smaller than the critical flaw size of the flywheel fracture analysis are utilized for the inspection of the flywheel. Based on the above information and the inspections outlined in the ISI Long-Term Plan, the intent of Regulatory Guide 1.14 is satisfied.

~~An additional stress and fracture evaluation was completed in November 1996 (WCAP-14535-A). The evaluation assumed a leak before break limitation on the maximum pump speed and 6000 cycles of reactor coolant pump starts and stops for a 60-year service life. The estimated radial crack extension was shown to be negligible even when assuming a large initial crack length. See Section 15.4.3 for further License Renewal information. (NRC SE dated 12/2005, NUREG-1839])~~

~~WCAP-15666-A, Revision 1, "Extension of Reactor Coolant Pump Motor Flywheel Examination," October 2003, builds on the arguments in WCAP-14535-A and provides additional rationale, including a risk assessment of all credible flywheel speeds. The risk assessment~~

~~followed the risk-informed methodology and guidelines of Regulatory Guide 1.174 to justify the RCP motor flywheel examination interval extension for all domestic Westinghouse plants from 10 years to 20 years. WCAP-15666-A concludes that the change in risk is below the Regulatory Guide CDF and LERF acceptable guidelines.~~

~~The NRC approved the use of the Topical Report in NRC SER "Safety Evaluation of Topical Report WCAP-15666, Extension of Reactor Coolant Pump Motor Flywheel Examination," May 5, 2003. The NRC SER has been incorporated into the "A" revision of the WCAP.~~

[INSERT A HERE]

All pressure bearing parts of the reactor coolant pump are analyzed in accordance with Article 4 of the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition. This includes the casing, the main flange, and the main flange bolts. The analysis includes pressure, thermal, and cyclic stresses, and these are compared with the allowable stresses in the Code. Mathematical models of the parts are prepared and used in the analysis which proceeds in two phases.

1. In the first phase, the design is checked against the design criteria of the ASME Code, with stress calculations using the allowable stress at design temperature. By this procedure, the shells are profiled to attain optimum metal distribution with stress levels adequate to meet the more exacting requirements of the second phase.

2. In the second phase, the interacting forces needed to maintain geometric capability between the various components are determined and applied to the components, along with the external load, to determine the final stress state of the components. This stress will also be used in the fatigue analyses. These results are finally compared with the Code allowable values.

There are no other sections of the Code which are specified as areas of compliance, but where Code methods, allowable stresses, fabrication methods, etc., are applicable to a particular component, these are used to give a rigorous analysis and conservative design.

Stress Analysis Reports are prepared on these components as described in Section 4.3. These reports include the calculation of stress intensities and a summary of fatigue usage factors. These reports are a part of the plant documentation on file with the applicant.

Reactor Coolant Pump Missile Protection

The construction of the loop compartment concrete walls is such that they enclose two sides of the reactor coolant pump area and protect the containment liner from loss-of-coolant accident generated missiles. The third side of the pump area is enclosed by the refueling canal wall. On the fourth side, a partition wall containing reinforcing steel and tension members divides the upper pump area from the steam generator compartment. The minimum compartment wall thickness is 30 inches.

Since there is no assumed mode of failure of the flywheel, no further design calculations were performed on this item as a missile. However, if a missile weight (W) 2500 lbs. (greater than 1/4 of flywheel) and a velocity (V) of 300 ft. per second were to strike the pump cavity walls, the penetration would be less than 20 inches, in accordance with the formula:

[INSERT A]

During normal operation, the reactor coolant pump flywheel possesses sufficient kinetic energy to potentially produce high-energy missiles in the unlikely event of failure. Conditions that may result in overspeed of the reactor coolant pump increase both the potential for failure and the kinetic energy. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway.

An evaluation of the probability of failure over the 60-year period of extended operation was performed in WCAP-14535-A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination" (Reference 17), for all operating Westinghouse plants and certain Babcock and Wilcox plants. The evaluation demonstrates that the flywheel design has high structural reliability with a very high flaw tolerance and negligible flaw crack extension over a 60-year service life. The NRC reviewed and approved the evaluation (WCAP-14535-A) for application with certain conditions and limitations (Reference 18). PBN verified the RCP flywheel material and invoked this analysis as the basis for reducing the frequency of performing RCP flywheel inspections (Reference 19).

WCAP-15666-A, Revision 1, "Extension of Reactor Coolant Pump Motor Flywheel Examination" (Reference 20), builds on the arguments in WCAP-14535-A and provides additional rationale, including a risk assessment of all credible flywheel speeds. WCAP-15666-A concludes that the change in risk is below Regulatory Guide 1.174 core damage frequency (CDF) and large early release frequency (LERF) acceptable guidelines. The NRC approved the use of this Topical Report in NRC SER, "Safety Evaluation of Topical Report WCAP-15666, Extension of Reactor Coolant Pump Motor Flywheel Examination" (Reference 21). This analysis was used as a basis for a revision of PBN Technical Specification TS 5.5.6 which increased the flywheel inspection interval from 10 years to 20 years. The inspection is a qualified in-place ultrasonic (UT) examination over the volume from the inner bore of the RCP flywheel to the circle of one-half the outer radius or a surface examination (magnetic particle testing and/or liquid penetrant testing) of the exposed surfaces defined by the volume of the disassembled RCP flywheels.

Considering the RCP flywheel probability of failure is part of the current licensing basis and is used to support safety determinations, and the probability of failure was based upon 60-year assumptions and 6,000 pump starts and stops, this fatigue analysis has been identified as a TLAA requiring evaluation for the subsequent period of extended operation.

RCP start and stop cycles for the 80-year subsequent period of extended operation (SPEO) have been projected using the same methodology utilized for the PBN 60-year PEO. The RCP start and stop cycles projected for the 60-year PEO were determined in the PBN response to RAI 4.4.2 (Reference 22). The projected number of RCP starts and stops on an annual basis for the SPEO are assumed to be the same as the PEO.

An evaluation of the probability of failure over the subsequent period of extended operation was performed by the PWROG. The evaluation is documented in PWROG-17011-NP-A, Revision 2, "Update for Subsequent License Renewal: WCAP-14535-A, 'Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,' and WCAP-15666-A, 'Extension of Reactor Coolant Pump Motor Flywheel Examination'''" (Reference 23). PWROG-17011-NP-A confirms that the analyses performed under WCAP-14535-A and WCAP-15666-A justifying inspection of the RCP flywheel once every 20-years remains appropriate for application up to 80 years of operation.

The fatigue crack growth calculations assumed 6,000 cycles of RCP start and stop for the 80-year plant life which significantly bounds the projected 80-year RCP start and stop counts of 500 cycles. Therefore, the fatigue crack growth is negligible over an 80-year life of the RCP flywheel, even when assuming a large initial crack length.

The evaluation demonstrates that the RCP flywheel design has a high structural reliability with a very high flaw tolerance and negligible fatigue flaw crack extension over an 80-year service life.

11. WCAP-14535, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,” January 1996.

12. NUREG-0800, Standard Review Plan Section 5.4.12, “Reactor Coolant System High Point Vents,” dated July 1981.

13. NRC Safety Evaluation, Point Beach Nuclear Plant Units 1 and 2, Wisconsin Electric Power Company, dated September 22. 1983.

14. NRC Safety Evaluation dated May 3, 2011, “Issuance of License Amendment Regarding Extended Power Uprate (TAC Nos. ME1044 and ME 1045).”

15. EPRI 1014986, “Pressurized Water Reactor Primary Water Chemistry Guidelines.”

16. NFPA 805 Fire Protection Program Design Document (FPPDD)

17. WCAP-14535A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,” November 1996 (ADAMS Accession No. ML18312A151)

18. NRC Letter, “Acceptance for Referencing of Topical Report WCAP-14535-A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,” dated September 12, 1996

19. NMC Letter to NRC, NRC 2001-059, “Reactor Coolant Pump Flywheel Inspection Interval Change Point Beach Nuclear Plant, Units 1 and 2,” dated September 17, 2001 (ADAMS Accession No. ML012700086)

20. WCAP-15666-A, “Extension of Reactor Coolant Pump Motor Flywheel Examination,” October 2003 (ADAMS Accession No. ML18303A413)

21. Safety Evaluation of Topical Report WCAP-15666, "Extension of Reactor Coolant Pump Motor Flywheel Examination," May 5, 2003 (ADAMS Accession No. ML031250595)

22. NMC Letter to NRC, NRC 2005-0008, “Response to Request for Additional Information Regarding the Point Beach Nuclear Plant License Renewal Application,” dated January 25, 2005 (ADAMS Accession No. ML050340169)

23. PWROG-17011-NP-A, Revision 2, “Update for Subsequent License Renewal: WCAP-14535A, ’Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination’ and WCAP-15666-A, ’Extension of Reactor Coolant Pump Motor Flywheel Examination,’” October 2019 (ADAMS Accession No. ML19318D189)

4.3 SYSTEM DESIGN EVALUATION

SAFETY FACTORS

The safety of the reactor vessel and all other Reactor Coolant System pressure containing components and piping is dependent on several major factors including design and stress analysis, material selection and fabrication, quality control, and operations control.

Reactor Vessel

The reactor vessel has a 132 in. ID and is within size limits for which good experience exists. A stress evaluation of the reactor vessel has been carried out in accordance with the rules of the applicable Edition of Section III of the ASME Code. The evaluation demonstrates that stress levels are within the stress limits of the Code. Table 4.3-1 presents a summary of the results of the stress evaluation. A summary of fatigue usage factors for components of the reactor vessel is given in Table 4.3-2.

The cycles specified for the fatigue analysis are the results of an evaluation of the expected plant operation coupled with experience from nuclear power plants such as Yankee Rowe. These cycles include five heatup and cooldown cycles per year, a conservative selection when the vessel may not complete more than one cycle per year during normal operation.

The vessel design pressure is 2485 psig, while the normal design operating pressure is 2235 psig. The resulting operating membrane stress is, therefore, amply below the code allowable membrane stress to account for operating pressure transients.

Appendix G to 10 CFR 50 establishes requirements for the fracture toughness of the reactor vessel pressure boundary which provide adequate margins of safety during any condition of normal operation, including anticipated operational occurrences, to which the pressure boundary may be subjected over its service lifetime. Section IV.A.2 of Appendix G requires that the reactor vessel be operated with pressure temperature limits at least as conservative as those obtained by following the methods of analysis and the required margins of safety of Appendix G of ASME Code Section XI.

See Section ~~15.4~~16.3 for the discussion of the fracture toughness methodology evaluation reviewed and approved by the NRC for Subsequent License Renewal for Unit 2. (~~NRC SE dated 12/2005, NUREG-1839~~[TBD])

Appendix G of ASME Code Section XI requires that pressure temperature limits be calculated: (a) using a safety factor of two on the principal membrane (pressure) stresses; (b) assuming a flaw at the surface with a depth of one quarter of the vessel wall thickness and a length of six times its depth; (c) using a conservative fracture toughness curve that is based on the lower bound of static, dynamic, and crack arrest fracture toughness tests on material similar to the Point Beach reactor vessel material; and (d) applying a 2 sigma margin in the determination the adjusted reference temperature (RT_{NDT}). The irradiation induced shift in RT_{NDT} is determined using the guidance of Regulatory Guide 1.99, Rev. 2 (Radiation Embrittlement of Reactor Vessel Materials) which is a conservative measure of material embrittlement.

Table 4.3-1 SUMMARY OF PRIMARY PLUS SECONDARY STRESS INTENSITY FOR COMPONENTS OF THE REACTOR VESSEL

Area	Stress Intensity (psi)	Allowable Stress 3 Sm (psi)
CRDM Nozzle	45,300	60,000
Closure Head at Flange	69,200	80,100
Vessel at Flange	71,100	80,100
Closure Studs	117,600	118,800
Primary Nozzles	48,800[a]	80,100
External Support Brackets	41,200	80,100
Core Support Pad	57,500	69,900
Bottom Head to Shell Juncture	28,600	80,100
Bottom Instrumentation	57,800	69,900
Safety Injection Nozzle	46,800	80,100
Vent Nozzle	53,600	60,000
Vessel Wall Transition	32,200	80,100
Instrumentation Port Head Adapter for Core Exit Thermocouple Nozzle Assembly	25,600	50,100

(~~NRC SE dated 12/2005, NUREG-1839~~[TBD])

a. Limiting value considering both the inlet and outlet nozzles.

Table 4.3-2 SUMMARY OF CUMULATIVE FATIGUE USAGE FACTORS FOR COMPONENTS OF THE REACTOR VESSEL

Item	Usage Factor*[a]
CRDM Nozzle	0.672
Closure Head at Flange	0.248
Vessel at Flange	0.992
Closure Studs	0.991
Primary Nozzles	0.155[b]
External Support Brackets	0.842
Core Support Pad	0.960
Bottom Head to Shell Juncture	0.004
Bottom Instrumentation	0.384
Safety Injection Nozzle	0.465
Vent Nozzle	0.023
Vessel Wall Transition	0.006
Instrumentation Port Head Adapter for Core Exit Thermocouple Nozzle Assembly	0.029

(~~NRC SE dated 12/2005, NUREG-1839~~[TBD])

* Covers all transients

[a] As defined in the applicable Edition of Section III of the ASME Boiler and Pressure Vessel Code, Nuclear Vessels

[b] Limiting value considering both the inlet and outlet nozzles.

See Section ~~15~~16 for the discussion of the fracture toughness methodology evaluation reviewed and approved by the NRC for Subsequent License Renewal for Unit 2 (~~NRC SE dated 12/2005, NUREG 1839~~[TBD]).

Six material surveillance capsules were located in the reactor vessel between the thermal shield and the vessel wall prior to initial startup. The capsules contain Charpy V-notch impact specimens, tensile specimens, Wedge Opening Loading (WOL) specimens from the shell plate or ring forgings of the reactor vessel and representative weld metal, and Charpy V-notch impact specimens of heat affected zone (HAZ) metal and the ASTM correlation monitor material. Dosimeters to measure the integrated neutron flux (fluence) and thermal monitors to measure temperature are also included in each of the six material test capsules. The removal schedules for the Unit 1 and 2 reactor vessel surveillance capsules are contained in TRM 2.2, Pressure Temperature Limits Report.

Pre-irradiation tests consisted of Charpy V-notch impact tests on the vessel shell plate or ring forgings, weld materials, HAZ metal, and on the correlation monitor material, and tensile tests performed on the vessel shell plate or ring forging and weld metal. The data established the nil ductility transition temperature, NDTT, for the materials. As a supplement to the plant specific material surveillance program for Point Beach, additional surveillance data is available through participation in the Babcock & Wilcox Owners Group Master Integrated Reactor Vessel Surveillance Program. This integrated program includes weld metal heats used in the construction of the Point Beach reactor vessels that are not included in the plant specific surveillance program for Point Beach.

Following establishment of the pre-irradiation mechanical properties of the subject materials, the ASME Boiler and Pressure Vessel Code adopted new fracture toughness requirements for ferritic components of nuclear reactor systems. The new Code provisions utilize fracture mechanics concepts as a method of analysis to prevent brittle fracture in reactor pressure vessels.

The method of fracture mechanics is based on the RT_{NDT} (reference nil-ductility temperature), which is defined as the greater of the drop weight nil ductility transition temperature (NDTT per ASTM E-208) or the temperature, which is 60 F less than the 50 ft-lb (and 35 mils lateral expansion) temperature as determined from Charpy specimens oriented normal to the rolling direction of the material. The RT_{NDT} of a given material is used to index that material to a reference stress intensity factor curve (KIR curve) as presented in Appendix G of ASME Boiler and Pressure Vessel Code Section XI. When a given material is indexed to the KIR curve, allowable stress intensity factors can be obtained for this material as a function of temperature. Allowable operating limits are then determined utilizing the allowable stress intensity factors and methodology of ASME Appendix G.

RT_{NDT}, and thus the operating limits of Point Beach Nuclear Plant, are adjusted to account for the effects of radiation on the reactor vessel material properties through the information provided by the reactor pressure vessel surveillance program or by utilizing embrittlement trend correlations prepared by the NRC or others. Details of the development and use of the surveillance program are found in WCAP-9513, June 1978;

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degree of leak tightness. The base liner is installed on top of the structural slab and is covered with concrete. The structure provides biological shielding for both normal and accident situations.

The nominal 3 ft. 6 in. thick cylindrical wall and 3 ft. thick dome are prestressed and post tensioned. The nominal 9 ft. thick concrete base slab is reinforced with high strength reinforcing steel. The slab is supported on H piles driven to refusal in the underlying bedrock.
The reactor containment structure for Point Beach Unit 2 is essentially identical in design and construction to that of Unit 1 except that it is oriented to conform to the overall site plan as shown in Figure 5.1-1.

Numerous mechanical and electrical systems penetrate the containment wall through welded steel penetrations as shown in Figure 5.1-2 and Figure 5.1-3.

In the concept of post-tensioned containment, the internal pressure load is balanced by the application of an opposing external pressure type load on the structure. Sufficient post-tensioning is used on the cylinder and dome to more than balance the internal pressure so that a margin of external pressure exists beyond that required to resist the design accident pressure. Nominal, bonded reinforcing steel is also provided to distribute strains due to shrinkage and temperature. Additional bonded reinforcing steel is used at penetrations and discontinuities to resist local moments and shears.

The internal pressure loads on the base slab are resisted by both the piles and the strength of the reinforced concrete slab. Thus, post tensioning is not required to exert an external pressure for this portion of the structure.

The post tensioning system design consists of:

1. Three groups of 49 dome tendons oriented at 120° to each other, for a total of 147 tendons anchored at the vertical face of the dome ring girder;

2. 168 vertical tendons anchored at the top surface of the ring girder and at the bottom of the base slab;

3. A total of 367 hoop tendons anchored at the six vertical buttresses.

Each tendon design consists of ninety 1/4 in. diameter wires with button headed BBRV type anchorages, furnished by Inland-Ryerson Construction Products Company. Actual number of tendon wires vary as documented in tendon surveillance reports. The tendons are housed in spiral wrapped corrugated thin wall sheathing and capped at each anchorage by a sheathing filler cap. After fabrication, the tendon is shop dipped in a petrolatum corrosion protection material, bagged, and shipped. After installation, the tendon sheathing and caps are filled with a corrosion preventive grease. In addition to this corrosion protection system, that portion of the tendon system in the base slab and the reinforcing steel are connected into an impressed current cathodic protection system. The cathodic protection system provided utilizes close coupled anodes to protect the interconnected liner, reinforcing bars, and tendon steel casings. The system ~~is~~was conservatively designed for a 40 year life and was reevaluated as adequate for an 80 year life.

The Capacity Reduction Factors 5 through 9 are in addition to those factors presented in ACI 318-63 Code and represent Bechtel's best judgement of how much under strength should be assigned to each material and condition not covered by the ACI Code.

The Φ factor is multiplied into the basic strength equation or into the basic permissible unit stress to obtain the dependable strength. The basic strength equation gives the "ideal" strength assuming materials are as strong as specified, sizes are as shown on the drawings, the workman- ship is excellent, and the strength equation itself is theoretically correct. The practical, dependable strength may be something less since all these factors vary.

Liner Plate Criteria

The design criteria which is applied to the containment liner to meet the specified leak rate under accident conditions are as follows:

1. That the liner is protected against damage by missiles coincident with the loss of coolant accident, excluding missiles generated by a rupture of the Reactor Coolant System piping (see Section 4.1 for additional details).

2. That the liner plate strains are limited to allowable values considerably below those that have been shown to result in leaktight vessels or pressure piping;

3. That the liner plate is prevented from developing significant distortion;

4. That all discontinuities and openings are well anchored to accommodate the forces exerted by the restrained liner plate, and that careful attention is paid to details of corners and connections to minimize the effects of discontinuities.

The leak tight criteria as applied to the liner plate Leak Chase Channels (LCCs) is discussed in Reference 1 and Reference 11.

The following sections of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Article 4, are used as guides in establishing allowable strain limits:

1. Paragraph N-412(m)
2. Paragraph N-414.5
3. Table N-413
4. Figure N-414, N-415(A)
5. Paragraph N-412(n)
6. Paragraph N-415.1

Implementation of the ASME design criteria requires that the liner material be prevented from experiencing significant distortion due to thermal load and that the stresses be considered from a fatigue standpoint. [Paragraph N 412(m)(2)]

The following fatigue loads are considered in the design of the liner plate:

1. Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is ~~60~~80 cycles for the plant life of ~~60~~80 years. (~~NRC SE dated 12/2005, NUREG-1839~~[TBD])

operating floor, or by special missile shields to block any passage of missiles to the containment walls. Potential missile sources are oriented so that the potential missile is intercepted by the shields and structures provided. A structure is provided over the control rod drive mechanisms to block any missiles generated from fracture of the mechanisms.

Missile protection is provided to comply with the following criteria:

1. The containment and liner are protected from loss of function due to damage by such missiles as might be generated in a loss of coolant accident.

2. The engineered safeguards system and components required to maintain containment integrity are protected against loss of function due to damage by the missiles defined below.

During the detailed plant design, the missile protection necessary to meet the above criteria was developed and implemented using the following methods:

1. Components of the reactor coolant system were examined to identify and to classify missiles according to size, shape, and kinetic energy for purposes of analyzing their effects.

2. Missile velocities were calculated considering both fluid and mechanical driving forces which can act during missile generation.

3. The structural design of the missile shielding takes into account both static and impact loads and is based upon the state of the art of missile penetration protection.

The types of missiles for which missile protection is provided are:

1. Valve stems
2. Valve bonnets
3. Instrument thimbles
4. Various types and sizes of nuts and bolts
5. Complete control rod drive mechanisms or parts thereof
6. Reactor coolant pump flywheels

Certain types of postulated accidents resulting in generation of missiles are considered incredible because of the material characteristics, inspections, quality control during fabrication, and conservative design of the particular component. Included in this category are missiles caused by massive, rapid failure of the reactor vessel, steam generator, pressurizer, and main coolant pump casings and drives.

Substructure Criteria

The vertical piling loads include the dead weight of the structure, all the live loads acting upon this piling, the vertical seismic load, and the vertical load in the pile due to overturning forces from the horizontal seismic load. In addition, under seismic or wind lateral loading, the piling is subjected to a bending moment due to a slight deflection of the structures in passive pressure on the soil. A cathodic protection system is provided which utilizes close coupled anodes to protect the piles. The system ~~is~~was conservatively designed for a 40 year life, derating manufacturer's recommendations for inert anodes by approximately 50%.

A concrete properties study using Point Beach samples was conducted at the University of California. (Reference 9) A similar study conducted on a nearly identical concrete mix has indicated a creep value of 0.125 x 10^{-6} In/In/Psi. Conversion of this unit creep data to hoop, vertical, and dome stress gives these values of stress loss in tendons:

Hoop - 5.5 Ksi
Vertical - 2.8 Ksi
Dome - 5.5 Ksi

A single creep loss figure of 400 x 10^{-6} in/in at 1500 psi (fcpi) in the concrete is used throughout the structure. This results in a prestress loss of 11.8 ksi in the prestressing steel.
The value used for shrinkage loss represents only that shrinkage that could occur after stressing. Since the concrete is, in general, well aged at the time of stressing, little shrinkage is left to occur and add to prestress loss.

The value of relaxation loss is based on information furnished by the tendon system vendor, Inland-Ryerson Construction Products Company.

Frictional loss parameters for unintentional curvature (K) and intentional curvature (m) are based on full scale friction test data. This data indicate actual values of K = 0.0003 and m = 0.125 versus the design values of K = 0.0003 and m = 0.156.

Assuming that the jacking stress for the tendons is 0.8 f'_s or 192,000 psi and using the assumed prestress loss parameters, the following tabulation shows the magnitude of the design losses and the final effective prestress at end of ~~60~~ 80 years for a typical dome, hoop, and vertical tendon. (~~NRC SE dated 12/2005, NUREG-1839~~[TBD])

	Dome (Ksi)	Hoop (Ksi)	Vertical (Ksi)
Jacking Stress	192	192	192
Friction Loss	18.5	20.8(1)	20.0
Seating Loss	0	0	0
Seating Stress	173.5	171.2	172.0

(1) Average of crossing tendons

	Dome (Ksi)	Hoop (Ksi)	Vertical (Ksi)
Elastic Loss	8.8	9.4	4.1
Creep Loss	11.8	11.8	11.8
Shrinkage Loss	3.0	3.0	3.0
Relaxation Loss	12.5	12.5	12.5
Final Effective Stress(2)	137.4	134.5	140.6

(2) This force does not include the effect of pressurization which increases the prestress force.

Water soluble nitrates (NO3) were determined by ASTM Method D992-52 with a limit of accuracy of 0.01 mg per liter. Finally, water soluble sulfides (S) were determined by ASTM Method D-1255-65T with a limit of accuracy of 1 ppm.

Stability data going back ten years from the time of construction indicates that the filler material will not deteriorate during the ~~40~~80-year life of the plant. Actually its chemical composition, being about 98% petroleum jelly, indicates that it would possess the normal stability of the linear hydrocarbons subjected to ambient temperature levels.

Galvanic corrosion normally occurs underground, under water or in the presence of a corrosive medium. Atmospheric conditions may cause surface attack but there is no galvanic corrosion unless metals of two different electrochemical levels are present and the medium between them permits current flow. Consequently if the materials used are steel, and precautions are taken to prevent water from providing a conducting path between them, there should be no galvanic corrosion (Reference 1).

If an electrolyte were to surround a stressed tendon, there is a possibility that the surface of the tendon would develop certain anodic corrosion centers (Reference 2). However, the corrosion would be caused by the fracturing of the naturally protecting oxide film on the surface of the steel.

Work done by Greene (Reference 3) and Unz (Reference 4) indicates that there is very little change in electric potential by extremely high stresses.

5.6.1.7 MATERIALS

1. Concrete

Ingredients

Cement	ASTM C-150 Type II
Flyash	ASTM C-350 Air
Air Entraining Agent	ASTM C-260
Water Reducing Agent	ASTM C-494 Type D (Plastiment)
Aggregate	ASTM C-33 (Fine aggregate is alluvial sand. Coarse aggregate is crushed dolomite.)

No Calcium Chloride was used in the concrete.

Strengths

Base Slab	4,000 psi at 90 days
Walls and Dome	5,000 psi at 28 days

Principal Placement Properties

Slump, maximum	2-3 in. at form
Air Content	3-5% at mixer
Temperature	Max. 70°F

2. Reinforcing Steel

ASTM Specification for reinforcing steel is the following:
A-15 Billet Steel - Intermediate Grade
A-432 Billet Steel - High Strength

b. High efficiency particulate filter media maintained its structural integrity in both the liquid and steam phase. No apparent change.

c. Asbestos separator pads showed some slight color bleaching, however, both steam and liquid phase samples maintained their structural integrity with no significant loss in rigidity.

d. Adhesive material for the HEPA/separator pad edges showed no deterioration or embrittlement and maintained its adhesive property.

e. Neoprene gasketing material is also satisfactory in both the steam and liquid phase. The material showed only weight gain and a shrinkage of 15% to 30% based on a superficial, one flat side area. The gasket thickness decreased about 10%. The gasket material was unrestrained during the exposure and hence the dimensional changes experienced are greater than those which would result in the fan cooler unit.

4. Power and Instrumentation Cable

Power and instrumentation cables have been subjected to the following series of tests and have shown acceptable performance.

a. Thermal aging of the cable. (The EQ program will manage thermal aging, as described in Chapter ~~15~~16. ~~NRC SE dated 12/2005, NUREG-1839~~[TBD])

b. Exposure to radiation ranging up to 2.0 x 10^8 rads.

c. Exposure to temperature, steam and chemical environment simulating post accident conditions.

REFERENCES

1. H. H. Uhlig, "The Corrosion Handbook," N.Y., 1948, Pg. 481-496.

2. Report of the RILEM-LABSE Committee on "Corrosion Problems with Prestressed Concrete," Session II, Paris, 1966, Pg. 3.

3. N. D. Greene and G. A. Satzman, "Corrosion" 20, No. 9, September 1964, Pg. 293t-298t.

4. Mr. Unz, "Corrosion" 18, No. 1, 5t-8t.

5. Bell, M. J., Bulkowski, J. E. and Picone, L. F., Investigation of Chemical Additives for Reactor Containment Sprays, WCAP-7153, March 1968. Westinghouse Proprietary.

6. ORNL Nuclear Safety Research and Development Program Bimonthly Report for July-August 1968, ORNL TM-2368, p. 78.

7. ORNL Nuclear Safety Research and Development Program Bimonthly Report for September-October 1968, ORNL TM-2425, p. 53.

8. Swandby, R. K., Chemical Engineer 69, 186 (November 12, 1962).

The tendon surveillance program for structural integrity and corrosion protection consists of visual and physical inspections as described in the Technical Specifications. The visual inspection checks for indications of abnormal material degradation, generally without dismantling the tendon. The physical inspection is more comprehensive. It involves a visual inspection followed by: (1) a lift-off test of each surveillance tendon to measure its pre-stressing force, (2) a de-tensioning of one tendon from each group, (3) a wire removal from each de-tensioned tendon for corrosion and tensile inspections, and (4) grease inspections and tests.

The inspection of the randomly selected tendons is sufficient to indicate any tendon corrosion that could possibly appear.

The inspection intervals, measured from the date of the initial proof test, are as follows:

One year from initial testing;

Three years from initial testing; and

Every five years thereafter.

Section 15.2.2, ASME Section XI, Subsections IWE and IWL ISI Programs, contain~~s~~ additional provisions for the period of extended operation. (NRC SE dated 12/2005, NUREG-1839)

Sections 16.2.2.29 and 16.2.2.30, ASME Section XI, Subsections IWE and IWL Aging Management Programs, contain~~s~~ additional provisions for the subsequent period of extended operation. ([TBD])

REFERENCES

1. Report on Containment Structural Test B-SIT-4, Point Beach Nuclear Plant Unit 1, October 29, 1970.

2. Report on Containment Structural Test B-SIT-5, Point Beach Nuclear Plant Unit 2, June, 1971.

3. Initial Integrated Leak Rate Test of the Reactor Containment Building, Point Beach Nuclear Plant Unit 1, June 25, 1970.

4. Initial Integrated Leak Rate Test of the Reactor Containment Building, Point Beach Nuclear Plant Unit 2, March 12, 1971.

5. 50.59 Evaluation 2008-002, Rev. 0, “U2-2CPP28 and 2CPP34 Removal of Leak Chase Channel,” approved April 17, 2008.

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The location of the wide-range detector relative to the reactor core is shown in Figure 7.6-3. The detector is mounted in its own well in the primary shield wall, 90 degrees from the opposing source/intermediate range detector wells.

The approximate detector range is shown on Figure 7.6-2. The dual fission chamber detector provides neutron flux measurements up to 100% power over twelve decades using two overlapping ranges (source range and percent log power). Each fission chamber is an ion chamber consisting of two uranium-coated aluminum electrodes, insulators, and fill gas. The fission chambers have a sensitive length greater than 40 inches and provide a neutron sensitivity of 2.0 cps/nv or greater.

Equipment for the wide-range channel includes the detector assembly and in-containment cable assembly, an amplifier cable assembly (from containment penetration to pre-amplifier), a pre-amplifier, a signal processor, and an output expansion module. The detector and cable assemblies are environmentally qualified for operation in a harsh containment environment. All electrical equipment is seismically supported. The channel is designed to operate under normal conditions and to survive a loss-of-coolant accident, providing reliable flux measurement before, during, and after an accident. The qualification of this equipment (detector and cable assemblies only) will be maintained during the subsequent period of extended operation by the EQ Program. (~~NRC SE dated 12/2005, NUREG-1839~~[TBD])

The pre-amplifier, signal processor, and output expansion module panels are mounted on the 8′ elevation of the control building. The pre-amplifier panel houses the power supplies and electronics which condition the detector signal for transmission to the signal processor panel. Signal conditioning includes amplification, pulse shaping, and discrimination against alpha, gamma and electronic noise. Circuitry in the pre-amplifier panel provides continuous self-diagnostics of the integrity of the detector, cables, and power supplies. The signal processor converts the signal from the pre-amplifier into signals that represent the source range count rate, the reactor power level, and the rate-of-change of the reactor power level. The output expansion module provides electrical isolation of output signals from the signal processor.

The wide-range channel function is indication only, and does not provide input to the reactor control or protection systems. The wide-range channel provides indication on the main control board and at four local safe-shutdown panels (two per unit), and also provides inputs to the plant process computer. Indicators provided on the main control board include source range count rate, source range start-up rate, wide range start-up rate, and wide range percent log power. Indicators provided on local safe-shutdown panels include source range count rate and source range start-up rate.

The wide-range channel is powered from the blue instrument bus supply. An alternate supply independent from the normal supply is provided via station batteries and a local inverter.

The wide range detection channel is environmentally qualified for operation in a harsh environment (detector and cable assemblies only). All electrical equipment is seismically supported. The system is designed to operate under normal conditions and to survive a loss-of-coolant accident (LOCA) environment, providing reliable measurement before, during, and after the LOCA. The qualification of this equipment (detector and cable assemblies only) will be maintained during the subsequent period of extended operation by the EQ Program. (~~NRC SE dated 12/2005, NUREG-1839~~[TBD])

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tank. During the recirculation phase of an accident, repairs to the component cooling system (loss) would not significantly impair reactor core cooling if, Containment Fan Coolers operate to remove containment heat, and core decay heat is transferred to the containment atmosphere by coolant boiling.

The normal power supplies for the component cooling water pumps P-11A and P-11B are safety-related 480 volt buses B-03 and B-04 respectively. In the event of a loss of off-site power without a coincident safety injection signal, at least one CC pump will be automatically started immediately when power is restored to the safeguards buses. If the loss of off-site power is coincident with a safety injection signal, automatic starting of the CC pumps will be blocked on the unit with the safety injection signal. The CC pumps are anticipated to be operating for the recirculation phase of an accident, with the alignment accomplished by operator action. The pumps also have a designated alternate source of power via B-08 or B-09 and an electrical disconnect switch. The alignment requires alternate power supply cables to be run from the disconnect switches to the pump motors.

A failure analysis of pumps, heat exchangers, and valves is presented in Table 9.1-2.

9.1.4 REQUIRED PROCEDURES AND TESTS

The active components of the component cooling system are in either continuous or intermittent use during normal plant operation. Periodic visual inspections and preventive maintenance can be conducted as necessary without interruption of cooling system operation. The inservice testing requirements are described in the PBNP Inservice Testing Program and the IST Background Document. The Closed -Cycle Cooling Water System Surveillance Program (FSAR Section 15.2.10) will be implemented during the period of extended operation (NRC SE dated 12/2005, NUREG-1839).
The Closed Treated Water Systems Aging Management Program (FSAR Section 16.2.2.12) will be implemented during the subsequent period of extended operation. ([TBD])

9.1.5 REFERENCES

1. PBNP FSAR Appendix A.6, Shared Systems Analysis
2. PBNP FSAR Appendix A.5, Seismic Design Analysis
3. NFPA 805 Fire Protection Program Design Document (FPPDD).
4. Not Used
5. "Safety Evaluation of the Request to Apply Leak-Before-Break Status to the Accumulator Line Piping at Point Beach Nuclear Plant, Units 1 and 2," November 7, 2000.
6. "Safety Evaluation of the Request to Apply Leak-Before-Break Status to Portions of the Residual Heat Removal Piping at Point Beach Nuclear Plant, Units 1 and 2," December 18, 2000.
7. "Safety Evaluation of the Request to Apply Leak-Before-Break Status to the Pressurizer Surge Line Piping at Point Beach Nuclear Plant, Units 1 and 2," December 15, 2000.
8. PBNP SE 2001-007, "Component Cooling Water System Closed Loop Inside Containment," February 24, 2001.

No credit is given for the VNPAB exhaust system in the control room or offsite dose bounding analysis described in FSAR Chapter 14.3.5, Radiological Consequences of a Loss of Coolant Accident (Reference 1).

Restoration of the VNPAB system within two hours of a LOOP assures adequate cooling for PAB safety related equipment during the worst case design basis accident (Reference 4).

The VNPAB system is classified as nonsafety-related, however components in the exhaust system required to direct radioactive releases in the PAB to the vent stack are classified as AQ (Augmented Quality). The seismic adequacy of the VNPAB exhaust system has been demonstrated using a methodology that follows the guidelines of Reference 2 and Reference 3. The VNPAB exhaust system design provides redundancy for all active mechanical components and active and passive electrical components needed to provide PAB exhaust flow. The design considers relay failures; failures of contacts to change state; and the shorting of relay, solenoid, or starter coils that could cause a damper to change to an undesirable state or prevent starting of a fan. The failure analysis does not include conductor short circuits or failure of one conductor, cable or device causing a failure of another conductor, cable, or device in the same location or raceway. The VNPAB exhaust system fans are supplied from the safety related Class 1E system by safety related circuit breakers which will isolate a fault on the nonsafety-related portions of the system and keep it from propagating to the Class 1E system. The fan motors and power cables located in potentially harsh environments are qualified for the expected environmental conditions (Reference 1).

9.5.4 REQUIRED PROCEDURES AND TESTS

Gaseous waste monitoring of the Primary Auxiliary Building ventilation system is performed per the requirements of the Offsite Dose Calculation Manual (ODCM).

The VNPAB exhaust system is included in the scope of the Maintenance Rule (10 CFR 50.65) and the Subsequent License Renewal (10 CFR 54.37(b)) programs. The W-30A&B filter fan motors and associated power cables, and the power cables to the W-21A&B stack fans are included in the scope of the EQ Program (10 CFR 50.49).

9.5.5 REFERENCES

1. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Regarding Use of Alternate Source Term (TAC Nos. ME0219 and ME0220)," dated April 14, 2011.
2. Seismic Qualification Utility Group (SQUG), "Generic Implementation Procedure (GIP) For Seismic Verification of Nuclear Plant Equipment," Revision 2, Corrected February 14, 1992.
3. Electric Power Research Institute Final Report 1014608, "Seismic Evaluation Guidelines for HVAC Duct and Damper Systems: Revision to 1007996," dated December, 2006.
4. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Re: Auxiliary Feedwater System Modification (TAC Nos. ME1081 and ME1082)," dated March 25, 2011.
5. NFPA 805 Fire Protection Program Design Document (FPPDD).

9.6.4 REQUIRED PROCEDURES AND TESTS

The SW system components are tested and inspected in accordance with Technical Specification surveillance criteria and surveillance frequencies by the Surveillance Frequency Control Program (Reference 10). Testing verifies motor-driven pump operability, and operability of all required valves.

The passive portions of the system are monitored in accordance with the Open-Cycle Cooling (Service) Water System Surveillance Program (Section 15.2.14) during the period of extended operation~~.~~ (NRC SE dated 12/2005, NUREG-1839). The passive portions of the system are monitored in accordance with the Open-Cycle Cooling (Service) Water System Aging Management Program (Section 16.2.2.11) during the subsequent period of extended operation. ([TBD])

The originally installed service water pumps underwent a hydrostatic test in the vendor shop at a test pressure of one and one-half times the shutoff head of the pump. In addition, the normal capacity vs. head characteristics were determined for each pump. During plant construction, the service water piping was hydrostatically tested in the field at one and one-half times design pressure. The welds in the shop fabricated service water piping were randomly radiographed in accordance with ASME Boiler and Pressure Vessel Code, Section VIII. Repair, replacement, and modification work on the service water system components is completed in accordance with the requirements of 10 CFR 50 Appendix B and ASME Section XI.

9.6.5 REFERENCES

1. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Re: Auxiliary Feedwater System Modification (TAC Nos. ME1081 and ME1082),” dated March 25, 2011.
2. Not Used
3. 10 CFR 50.59/72.48 Screening (SCR) 2013-0024, “Revise TRM 3.7.7, OI 70, TS 33, TS 34, AOP 13A, AOP 8F, FSAR 9.6.1, OI 155, PC 97 Parts 1-8, and 1(2)-SOP-VNCC-001-4 to Allow 85F SW Inlet Temperature and to specify operability limits on low pump bay level for the G01/G02 EDGs and the lower elevation CFCs,” dated March 15, 2013.
4. NRC Safety Evaluation, “Point Beach Nuclear Plant, Units 1 and 2 – Issuance of Amendments Re: Service Water System Operability (TAC Nos. MB4630 and MB4631), dated August 29, 2002.
5. NFPA 805 Fire Protection Program Design Document (FPPDD).
6. Screening Evaluation Work Sheet SQ-002126, “North Service Water Header Zurn Strainer, SW-2911-BS,” Revision 1, 03/07/03.
7. Screening Evaluation Work Sheet SQ-002127, “South Service Water Header Zurn Strainer, SW-2912-BS,” Revision 1, 03/07/03.
8. Bechtel Topical Report B-TOP-3, “Design Criteria for Nuclear Power Plants Against Tornadoes,” (Proprietary) dated March 12, 1970.
9. Amirikian, Araham, “Design of Protective Structures, A New Concept of Structural Behavior,” Bureau of Yards and Docks, Department of the Navy, P 51, August 1950.
10. NRC Safety Evaluation, “Point Beach Nuclear Plant Units 1 and 2 - Issuance of Amendments Regarding Relocation of Surveillance Frequencies to Licensee Control (TAC NOS. MF4379 and MF4380),” dated July 28, 2015.

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instantaneously. The site boundary whole body dose resulting from the above assumptions, and using the most conservative X/Q values shown in Figure 2.6-8, is less than 0.03 rem.

This discussion is provided for historical purposes. The cryogenic system was never used, and is not operational. Major portions of the system have been abandoned in place. Thus, the reference to a 40-year operating period would still bound an ~~60~~80-year plant operating period (~~NRC SE dated 12/2005, NUREG-1839~~TBD).

The noble gases absorbed in the cryogenic absorber vessel can be desorbed at the end of each 180 day cryogenic cycle and stored in one of the existing gas decay tanks. The resulting activity would, if accumulated over a 40-year period in this single gas decay tank, reach a maximum value of 50,000 curies Krypton-85. Xenon-133 would reach a maximum value of 2,100 curies. The whole body dose resulting from an instantaneous release of the gas decay tank contents would be 0.7 rem, which is less than that described previously for a single gas decay tank rupture.

11.2.6 REFERENCES

1. Letter PBW-WMP-416, Westinghouse to WE dated December 4, 1967.
2. Westinghouse Calculation Note, CN-CRA-99-15, WEP/WIS Annual Releases (GALE Code Analysis), Revision 1, September 30, 2009.
3. K.F. Eckerman et al, “Limiting Values of Radionuclide Intake and Air Concentration and dose Conversion Factors for Inhalation, Submersion, and Ingestion,” Federal Guidance Report No. 11, Environmental Protection Agency, September 1988.
4. K.F. Eckerman and J.C. Ryman, “External Exposure to Radionuclides in Air, Water, and Soil,” Federal Guidance Report No. 12, Environmental Protection Agency, September 1993.
5. Branch Technical Position 11-5, Revision 3, “Postulated Radioactive Releases due to a Waste Gas System Leak or Failure,” March 2007. (Contained in NUREG-0800.)
6. Westinghouse Calculation CN-REA-08-7, RCS, VCT, and GDT Sources for the Point Beach EPU, Revision 0, September 19, 2008.
7. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045),” dated May 3, 2011.
8. Westinghouse Calculation, CN-CRA-08-45, Charcoal Delay Tank Doses for the Extended Power Uprate, Revision 1.
9. Westinghouse Calculation, CN-CRA-08-44, Volume Control Tank Rupture and Waste Gas Decay Tank Rupture Radiological Doses for the Extended Power Uprate, Revision 1.

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Aging Management Program

The ~~Aging Management Program,~~ Reactor Vessel Internals Aging Management Program (FSAR Section ~~15.2.17~~16.2.2.7) provides additional information for monitoring during the subsequent period of extended operation (~~NRC SE dated 12/2005, NUREG-1839~~TBD).

References

1. S. Fabic: "Computer Program WHAM for Calculation of Pressure, Velocity, and Force Transients in Liquid Filled Piping Networks," Kaiser Engineers Report No. 67-49-R (November 1967).
2. K. Takeuchi: "MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," WCAP 8708-PA, WCAP 8709-A (Non-proprietary), September, 1977.
3. WCAP-15133 "Determination of Acceptable Baffle-Barrel-Bolting for Point Beach Units 1 and 2."
4. Westinghouse Engineering Letter NSD-E-MSI-99-036 "Evaluation of Case 132 and 132 no 722 Baffle Bolting Patterns," dated January 28, 1999.
5. WCAP-15029 "Westinghouse Methodology for Evaluating the acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions," by P.E. Schwirian, et. al., Westinghouse Electric Company, 1998.
6. NRC Safety Evaluation of Topical Report WCAP-15029 "Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distribution Under Faulted Load Conditions" (TAC NO. MA 1152)," dated November 10, 1998.
7. Westinghouse Calculation Note CN-RIDA-08-37, Rev. 2, "WEP/WIS (Point Beach Units 1 and 2) RPV System LOCA Analysis - EPU Program," November 20, 2008.
8. Westinghouse Calculation Note CN-RIDA-08-73, Rev. 0, "WEP/WIS (Point Beach Units 1 and 2) EPU - Guide Tube Control Rod Insertability," November 24, 2008.
9. K. Takeuchi: "MULTIFLEX 3.0, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic - Structural System Dynamics Advanced Beam Model," WCAP-9735 Rev. 2, WCAP-9736 (Non-proprietary) Rev. 1, February 1998.

Appendix A
Technical Requirements Manual Update

This section provides a markup of the Point Beach Units 1 and 2 Technical Requirements Manual delineating changes that will be required for subsequent license renewal.

TABLE 1*
POINT BEACH NUCLEAR PLANT UNIT 1
REACTOR VESSEL SURVEILLANCE CAPSULE REMOVAL SCHEDULE

Capsule Identification Letter	**Approximate Removal Date****
V	EOC-1 (Sept 1972)
S	EOC-3 (Dec 1975)
R	EOC-5 (Oct 1977)
T	EOC-11 (Mar 1984)
P	EOC-21 (Apr 1994 - Stored in SFP)
N	Standby

TABLE 2*
POINT BEACH NUCLEAR PLANT UNIT 2
REACTOR VESSEL SURVEILLANCE CAPSULE REMOVAL SCHEDULE

Capsule Identification Letter	**Approximate Removal Date****
V	EOC-1 (Nov 1974)
T	EOC-3 (Mar 1977)
R	EOC-5 (Apr 1979)
S	EOC-16 (Oct 1990)
P	EOC-22 (Jun 1997- Stored in SFP)
N	Standby
Supplemental Capsule “A” ***	~~43 EFPY (~Fall 2024)~~ **51 EFPY (~Spring 2035)**

* During the period of extended operation, reactor vessel surveillance capsules will be removed and tested in accordance with the schedule contained in the most recently NRC approved Pressurized Water Reactor Owners Group (PWROG) Master Integrated Reactor Vessel Surveillance Program (MIRVSP) Document. (Ref. 5.8)

** For capsules that have not been withdrawn yet, the actual dates will be adjusted to coincide with the first refueling outage that meets or exceeds the scheduled EFPY. ~~closest scheduled plant refueling outage.~~

*** Supplemental Capsule “A” (also identified as Supplemental Capsule “W” in some documents) was installed in Cycle 25 and is described in WCAP-15856. (Ref 5.17) The removal date is provided in effective full power years (EFPY) as agreed between the NRC and PWROG. (Ref. 5.8)

APPENDIX B

AGING MANAGEMENT PROGRAMS

POINT BEACH NUCLEAR PLANT UNITS 1 AND 2

SUBSEQUENT LICENSE RENEWAL APPLICATION

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B.1 Introduction

B.1.1 Overview

The Subsequent License Renewal (SLR) Aging Management Program (AMP) descriptions are provided in this appendix for each program credited for managing aging effects based upon the Aging Management Review (AMR) results provided in Sections 3.1 through 3.6 of this Subsequent License Renewal Application (SLRA).

In general, there are four types of AMPs:

- Prevention programs that preclude aging effects from occurring;
- Mitigation programs that slow the effects of aging;
- Condition monitoring programs that inspect/examine for the presence and extent of aging; and
- Performance monitoring programs that test the ability of a structure or component to perform its intended function.

More than one type of AMP may be implemented for systems, structures, and components (SSCs) to ensure that aging effects are managed.

Part of the demonstration that the effects of aging are adequately managed is to evaluate credited programs and activities against certain required attributes. Each of the AMPs described in this section has 10 elements which are consistent with the attributes described in Table 2, "Aging Management Programs Element Descriptions," of NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report."

Credit has been taken for existing PBN plant programs whenever possible. However, some existing PBN programs aligned with multiple NUREG-2191 AMPs, and some NUREG-2191 AMPs aligned with multiple PBN programs, therefore the existing PBN AMPs to be continued for SLR will be renamed as applicable to align with the NUREG-2191 AMP names. New PBN AMPs align with the NUREG-2191 AMP names. All existing PBN programs and activities associated with in-scope SLR SSCs were considered to determine whether they include the necessary actions to manage the effects of aging.

Current PBN license renewal programs are based on NUREG-1801 (GALL), Revision 0 and include the required SLR 10-element attributes. These current programs have been demonstrated to adequately manage the identified aging effects during the original period of extended operation (PEO). If an existing program does not adequately manage an identified aging effect, the finding is entered into the Corrective Action Program and the program is enhanced, as necessary.

Consistent with the discussion above, the following new programs will be created at PBN for the purposes of SLR:

- the PBN Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP (Section B.2.3.6),
- the PBN Selective Leaching AMP (Section B.2.3.21),

- the PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP (Section B.2.3.25),
- the PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section B.2.3.28),
- the PBN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (Section B.2.3.40),
- the PBN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (Section B.2.3.41),
- the PBN Metal Enclosed Bus AMP (Section B.2.3.42),
- the PBN Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (Section B.2.3.43), and
- the PBN High-Voltage Insulators AMP (Section B.2.3.44).

These new AMPs will be consistent with the 10 elements of their respective NUREG-2191 AMPs. The following programs each have exception(s) justified by technical data:

- the PBN Water Chemistry AMP (Section B.2.3.2),
- the PBN Reactor Head Closure Stud Bolting AMP (Section B.2.3.3),
- the PBN Reactor Vessel Internals AMP (Section B.2.3.7),
- the PBN Steam Generators AMP (Section B.2.3.10),
- the PBN Open-Cycle Cooling Water System AMP (Section B.2.3.11),
- the PBN Closed Treated Water Systems AMP (Section B.2.3.12),
- the PBN Fuel Oil Chemistry AMP (Section B.2.3.18),
- the PBN Reactor Vessel Material Surveillance AMP (Section B.2.3.19),
- the PBN Buried and Underground Piping and Tanks AMP (Section B.2.3.27),
- the PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section B.2.3.28),
- the PBN ASME Section XI, Subsection IWF AMP (Section B.2.3.31).

B.1.2 Method of Discussion

For those PBN AMPs that are consistent with the AMP descriptions and assumptions made in Sections X and XI of NUREG-2191, or are consistent with exceptions or enhancements, each AMP discussion is presented in the following format:

- A Program Description abstract of the overall program form and function is provided. This Program Description also includes whether the program is existing (and if it replaces LR programs) or new for SLR.
- A NUREG-2191 consistency statement is made about the AMP.
- Exceptions to the NUREG-2191 program are outlined and a justification for the exception(s) is provided.
- Enhancements or additions to make the PBN AMP consistent with the respective NUREG-2191 AMP are provided. A proposed schedule for completion is discussed. This SLRA defines “enhancements” as any changes to plant programs or activities that need to be implemented in order to align with the guidance of NUREG-2191.
- Operating Experience (OE) information specific to the AMP is provided.

- A Conclusion section provides a statement of reasonable assurance that the PBN AMP for SLR is effective or will be effective when implemented if new or enhanced.

B.1.3 Quality Assurance Program and Administrative Controls

The NextEra Quality Assurance (QA) Program for PBN implements the requirements of 10 CFR 50, Appendix B, "Quality Assurance Requirements for Nuclear Power Plants and Fuel Reprocessing Plants." and is consistent with the summary in Appendix A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)," of NUREG-2192. The NextEra QA Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related SSCs and commodity groups that are included within the scope of the AMPs. Generically, the three elements are applicable as follows.

Corrective Actions:

A single PBN Corrective Action Program (CAP) is applied regardless of the safety classification of the SSC or commodity group. The PBN CAP requires the initiation of a Condition Report (CR) for actual or potential problems, including unexpected plant equipment degradation, damage, failure, malfunction, or loss of function. Site documents that implement AMPs for SLR direct that a CR be prepared in accordance with those procedures whenever non-conforming conditions are found (i.e., the acceptance criteria are not met). Equipment deficiencies are corrected through the Work Control Process in accordance with plant procedures. The PBN CAP specifies that for equipment deficiencies a CR be initiated for condition identification, assignment of significance level and investigation class, investigation, corrective action determination, investigation report review and approval, action tracking, and trend analysis.

The following statement applies to all the PBN AMPs for SLR:

> *Conditions adverse to quality; such as failures, malfunctions, deficiencies, 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 condition 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 is documented and reported to appropriate levels of management. The corrective action controls of the Quality Assurance Program, as described in the NextEra Energy Quality Assurance Topical Report (FPL-1), will be used to meet Element 7, Corrective Actions.*

Confirmation Process:

The focus of the confirmation process is on the follow-up actions that must be taken to verify effective implementation of corrective actions. The measure of effectiveness is in terms of correcting and precluding repetition of adverse conditions. The PBN CAP includes provisions for timely evaluation of adverse conditions and implementation of corrective actions required, including root cause determinations and prevention of recurrence where appropriate (e.g., significant conditions adverse to quality). The PBN CAP provides for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure effective corrective actions are taken. The PBN CAP also includes monitoring for potentially adverse trends. The existence of an adverse trend due to recurring or repetitive adverse conditions results in the initiation of a CR. The AMPs required for SLR would also result in identification of related unsatisfactory conditions due to ineffective corrective action.

Since the same 10 CFR 50, Appendix B, corrective actions and confirmation process is applied for nonconforming safety-related and nonsafety-related SSCs subject to AMR for SLR, the CAP is consistent with the NUREG-2191 and NUREG-2192 elements.

The following statement is applicable to all the PBN AMPs for SLR:

Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The Quality Assurance Program, as described in the NextEra Energy Quality Assurance Topical Report (FPL-1), will be used to meet Element 8, Confirmation Process.

The confirmation process is part of the corrective action program and includes the following:

- *Reviews to assure that proposed corrective actions are adequate*
- *Tracking and reporting of open corrective actions*
- *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 PBN aging management programs and activities.

<u>Administrative Controls:</u>

The document control process applies to all generated documents, procedures, and instructions regardless of the safety classification of the associated SSC or commodity group. Document control processes are implemented in accordance with the requirements of 10 CFR 50, Appendix B. Administrative controls procedures provide information on procedures, instructions and other forms of administrative control documents, as well as guidance on classifying these documents into the proper document type and as-building frequency. Revisions will be made to procedures and instructions that implement or administer AMP requirements for the purposes of managing the associated aging effects for the subsequent period of extended operation (SPEO).

The following statement is applicable to all the PBN AMPs for SLR:

Site QA procedures, review, and approval processes *and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50,*

Appendix B. The Quality Assurance Program, as described in the NextEra Energy Quality Assurance Topical Report (FPL-1), will be used to meet the required Administrative Controls.

B.1.4 Operating Experience

Internal OE (also referred to as plant-specific OE) and external OE (also referred to as industry OE) sources are captured and systematically reviewed on an ongoing basis in accordance with the NEE QA Program and the PBN OE program. The PBN OE program (part of the NEE fleet OE program) meets the requirements of NUREG-0737 (Reference 1.6.47), “Clarification of TMI Action Plan Requirements,” Item I.C.5, “Procedures for Feedback of Operating Experience to Plant Staff.” The PBN OE program also meets the requirements of NEI 14-12 (Reference 1.6.48), “Aging Management Program Effectiveness.” The OE program interfaces with and relies on active participation in the Institute of Nuclear Power Operations (INPO) OE program, as endorsed by the U.S. Nuclear Regulatory Commission (NRC).

OE is used at PBN Units 1 and 2 to enhance existing programs and AMPs, prevent repeat events, and prevent events that have occurred at other plants. As part of the NEE fleet, PBN Units 1 and 2 receive OE (internal and external to NEE) daily. The OE process screens, evaluates, and acts on OE documents and information to prevent or mitigate the consequences of similar events. The OE process reviews OE from external and internal sources. External OE includes INPO documents, NRC documents (e.g., Information Notices (IN), Regulatory Information Summaries (RIS), Interim Staff Guidance (ISG)), and other documents (e.g., Licensee Event Reports (LER) and 10 CFR Part 21 Reports). In addition, the license renewal interim staff guidance documents and revisions to the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report are considered as sources of industry OE and evaluated accordingly. Relevant foreign and domestic research and development are also reviewed. Relevant research and development sources include: (a) industry consensus standards development organizations (e.g., ASME, IEEE, ACI, API, NACE, International Organization for Standardization); (b) Electric Power Research Institute (EPRI); (c) generic communications issued by the staff based on research conducted by national labs used by the NRC; and (d) NSSS vendor and owner’s groups.

Operating experience involving age-related degradation is tracked and trended such that adverse trends are entered into the corrective action program for evaluation. Operating experience identified as potentially involving aging is evaluated with regard to: (a) systems, structures, and components, (b) materials, (c) environments, (d) aging effects, (e) aging mechanisms, (f) AMPs, and (g) the activities, criteria, and evaluations integral to the elements of the AMPs. Existing AMPs have an established performance feedback mechanism in place by requiring the OE program to evaluate both internal and external OE for applicability through entry into the CAP. This process provides reasonable assurance that AMPs are informed and enhanced, if necessary, by relevant OE. PBN meets the requirements of NEI 14-13 (Reference 1.6.49) regarding the use of industry OE for AMPs.

Assessments of the effectiveness of the AMPs and activities are conducted on a periodic basis that is not to exceed once every 5 years. The assessments include evaluation of the AMP or activity against the latest NRC and industry guidance documents and standards that are relevant to the particular program or activity. If there is an indication that the effects of aging are not being adequately managed, then a corrective action is entered into the 10 CFR Part 50, Appendix B, program to either enhance the AMPs or develop and implement new AMPs, as appropriate. PBN is actively managing its current AMPs and program overall and seeking to identify areas that would improve the effectiveness of aging management. Consequently, a License Renewal AMP Effectiveness review was completed to identify gaps related to the effectiveness of the current PBN license renewal AMPs in accordance with NEI 14-12, Revision 0, “Aging Management Program Effectiveness”. The assessment was completed in May 2018 and included all active Aging Management Programs referenced in the UFSAR as managing the effects of aging for the renewed operating license.

The assessment was conducted by the assigned program owner and reviewed by the applicable supervisor and a member of the Renewed License Program Peer Team. The individual AMPs were reviewed against the criteria provided by NEI 14-12, which provides a standard approach based on the 10 Program Elements required for each Aging Management Program. Any criteria which was not met, was identified as a gap. The gaps for each element for a particular AMP were evaluated comprehensively to determine if the combined gaps left uncorrected would result in a “failed program element,” or were primarily administrative in nature. Specifically, elements were considered to be “failed” if the combination of identified gaps could have prevented the proper implementation of the associated element. Elements were not considered to be failed if the gap identified an administrative error that did not cause improper implementation or did not have a significant consequence.

All Programs were judged to still be effective. No ineffective programs were identified. During this assessment additional items were also identified that will be addressed along with the gaps. One of the primary goals for these effectiveness reviews was to be a revision to the AMP to update OE and at a minimum, include a paragraph providing the results of the effectiveness review.

A recent internal OE review identified several findings in implementation of aging management programs during the current period of extended operation (PEO). Each finding was reviewed for cause, and actions were generated for resolution and to identify any additional extent of condition. The findings were primarily related to a lack of advocacy for work completion and corrective actions not completed as written. The findings did not result in any challenges to component operability, or significant loss of margin.

The processes and procedures for implementing and overseeing aging management programs have since been enhanced. These enhancements include processes that would prevent recurrence of these and similar issues. Examples include:

- System health process was revised to emphasize use of risk/priority color coding for conditions involving age-related degradation mechanisms.

- Periodic internal OE reviews that monitor for completeness of corrective actions assignments to ensure they account for cause, extent of condition and predicted rate of degradation.

Each AMP summary in this appendix contains a discussion of OE relevant to the AMP. This information was obtained through the review of internal OE captured by the PBN CAP, Program Assessments, Program Health Reports, and through the review of external OE. Additionally, to provide assurance that OE was fully understood and discussed, interviews were performed with system engineers, program engineers, and other plant personnel. New AMPs utilize internal and/or external OE, as applicable, and discuss the OE and associated corrective actions as they relate to implementation of the new AMP. The OE in each AMP summary identifies past corrective actions that have resulted in program enhancements and provides objective evidence that the effects of aging have been, and will continue to be, adequately managed so that the intended functions of the structures and components within the scope of each AMP will be maintained during the SPEO.

As described above, the existing OE process at PBN, in conjunction with the PBN CAP, has proven to be effective in learning from adverse conditions and events, and improving programs that address age-related degradation.

B.1.5 Aging Management Programs

Table B-1 lists the PBN AMPs for SLR in the order that their respective AMP appears in NUREG-2191. Table B-1 states the respective AMP section numbers and whether the AMP is considered a new program or an existing program (or a portion of an existing program) at PBN. Existing AMPs are based on either an existing LR AMP or existing plant program. Additionally, Table B-2 lists the PBN AMPs for SLR in alphabetical order. All the AMPs either are or will be consistent with their respective AMPs discussed in NUREG-2191 unless otherwise noted as an exception.

Table B-1
List of Point Beach Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
X.M1	B.2.2.1	Fatigue Monitoring	Existing
X.M2	B.2.2.2	Neutron Fluence Monitoring	Existing
X.S1	B.2.2.3	Concrete Containment Unbonded Tendon Prestress	Existing
X.E1	B.2.2.4	Environmental Qualification of Electric Equipment	Existing
XI.M1	B.2.3.1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Existing
XI.M2	B.2.3.2	Water Chemistry	Existing
XI.M3	B.2.3.3	Reactor Head Closure Stud Bolting	Existing
XI.M4	N/A	BWR Vessel ID Attachment Welds Not Applicable (PBN U1 and U2 are PWRs)	N/A
XI.M7	N/A	BWR Stress Corrosion Cracking Not Applicable (PBN U1 and U2 are PWRs)	N/A
XI.M8	N/A	BWR Penetrations Not Applicable (PBN U1 and U2 are PWRs)	N/A
XI.M9	N/A	BWR Vessel Internals Not Applicable (PBN U1 and U2 are PWRs)	N/A
XI.M10	B.2.3.4	Boric Acid Corrosion	Existing

Table B-1
List of Point Beach Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
XI.M11B	B.2.3.5	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	Existing
XI.M12	B.2.3.6	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel	New
XI.M16A	B.2.3.7	Reactor Vessel Internals	Existing
XI.M17	B.2.3.8	Flow-Accelerated Corrosion	Existing
XI.M18	B.2.3.9	Bolting Integrity	Existing
XI.M19	B.2.3.10	Steam Generators	Existing
XI.M20	B.2.3.11	Open-Cycle Cooling Water System	Existing
XI.M21A	B.2.3.12	Closed Treated Water Systems	Existing
XI.M22	N/A	Boraflex Monitoring Not Applicable (PBN U1 and U2 do not credit Boraflex as a neutron absorber in their criticality analyses.)	N/A
XI.M23	B.2.3.13	Inspection of Overhead Heavy Load Handling Systems	Existing
XI.M24	B.2.3.14	Compressed Air Monitoring	Existing
XI.M25	N/A	BWR Reactor Water Cleanup System Not Applicable (PBN U1 and U2 are PWRs)	N/A
XI.M26	B.2.3.15	Fire Protection	Existing
XI.M27	B.2.3.16	Fire Water System	Existing
XI.M29	B.2.3.17	Outdoor and Large Atmospheric Metallic Storage Tanks	Existing
XI.M30	B.2.3.18	Fuel Oil Chemistry	Existing
XI.M31	B.2.3.19	Reactor Vessel Material Surveillance	Existing
XI.M32	B.2.3.20	One-Time Inspection	Existing
XI.M33	B.2.3.21	Selective Leaching	New
XI.M35	B.2.3.22	ASME Code Class 1 Small-Bore Piping	Existing
XI.M36	B.2.3.23	External Surfaces Monitoring of Mechanical Components	Existing
XI.M37	B.2.3.24	Flux Thimble Tube Inspection	Existing
XI.M38	B.2.3.25	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	New
XI.M39	B.2.3.26	Lubricating Oil Analysis	Existing
XI.M40	N/A	Monitoring of Neutron-Absorbing Materials other than Boraflex (PBN U1 and U2 do not credit other neutron absorbing materials in their criticality analyses.)	N/A
XI.M41	B.2.3.27	Buried and Underground Piping and Tanks	Existing
XI.M42	B.2.3.28	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	New
XI.S1	B.2.3.29	ASME Section XI, Subsection IWE	Existing
XI.S2	B.2.3.30	ASME Section XI, Subsection IWL	Existing
XI.S3	B.2.3.31	ASME Section XI, Subsection IWF	Existing
XI.S4	B.2.3.32	10 CFR Part 50, Appendix J	Existing
XI.S5	B.2.3.33	Masonry Walls	Existing
XI.S6	B.2.3.34	Structures Monitoring	Existing

Table B-1
List of Point Beach Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
XI.S7	B.2.3.35	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Existing
XI.S8	B.2.3.36	Protective Coating Monitoring and Maintenance	Existing
XI.E1	B.2.3.37	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	Existing
XI.E2	B.2.3.38	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits	Existing
XI.E3A	B.2.3.39	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	Existing
XI.E3B	B.2.3.40	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements	New
XI.E3C	B.2.3.41	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	New
XI.E4	B.2.3.42	Metal Enclosed Bus	New
XI.E5	N/A	Fuse Holders Not Applicable (PBN U1 and U2 do not have any components within this program scope.)	N/A
XI.E6	B.2.3.43	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements	New
XI.E7	B.2.3.44	High-Voltage Insulators	New

Table B-2
Aging Management Programs

PBN Aging Management Program	Section	NUREG-2191 Section
10 CFR Part 50, Appendix J	B.2.3.32	XI.S4
ASME Code Class 1 Small-Bore Piping	B.2.3.22	XI.M35
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B.2.3.1	XI.M1
ASME Section XI, Subsection IWE	B.2.3.29	XI.S1
ASME Section XI, Subsection IWF	B.2.3.31	XI.S3
ASME Section XI, Subsection IWL	B.2.3.30	XI.S2
Bolting Integrity	B.2.3.9	XI.M18
Boric Acid Corrosion	B.2.3.4	XI.M10
Buried and Underground Piping and Tanks	B.2.3.27	XI.M41
Closed Treated Water Systems	B.2.3.12	XI.M21A
Compressed Air Monitoring	B.2.3.14	XI.M24
Concrete Containment Unbonded Tendon Prestress	B.2.2.3	X.S1
Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	B.2.3.5	XI.M11B
Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.43	XI.E6
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.37	XI.E1
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits	B.2.3.38	XI.E2
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.40	XI.E3B
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.41	XI.E3C
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.39	XI.E3A
Environmental Qualification of Electric Equipment	B.2.2.4	X.E1
External Surfaces Monitoring of Mechanical Components	B.2.3.23	XI.M36
Fatigue Monitoring	B.2.2.1	X.M1
Fire Protection	B.2.3.15	XI.M26
Fire Water System	B.2.3.16	XI.M27
Flow-Accelerated Corrosion	B.2.3.8	XI.M17
Flux Thimble Tube Inspection	B.2.3.24	XI.M37
Fuel Oil Chemistry	B.2.3.18	XI.M30
High-Voltage Insulators	B.2.3.44	XI.E7

Table B-2
Aging Management Programs

PBN Aging Management Program	Section	NUREG-2191 Section
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B.2.3.25	XI.M38
Inspection of Overhead Heavy Load Handling Systems	B.2.3.13	XI.M23
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B.2.3.35	XI.S7
Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B.2.3.28	XI.M42
Lubricating Oil Analysis	B.2.3.26	XI.M39
Masonry Walls	B.2.3.33	XI.S5
Neutron Fluence Monitoring	B.2.2.2	X.M2
One-Time Inspection	B.2.3.20	XI.M32
Open-Cycle Cooling Water System	B.2.3.11	XI.M20
Outdoor and Large Atmospheric Metallic Storage Tanks	B.2.3.17	XI.M29
Protective Coating Monitoring and Maintenance	B.2.3.36	XI.S8
Reactor Vessel Internals	B.2.3.7	XI.M16A
Reactor Head Closure Stud Bolting	B.2.3.3	XI.M3
Reactor Vessel Material Surveillance	B.2.3.19	XI.M31
Selective Leaching	B.2.3.21	XI.M33
Steam Generators	B.2.3.10	XI.M19
Structures Monitoring	B.2.3.34	XI.S6
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel	B.2.3.6	XI.M12
Water Chemistry	B.2.3.2	XI.M2

B.2 AGING MANAGEMENT PROGRAMS

B.2.1 NUREG-2191 Aging Management Program Correlation

The correlation between the NUREG-2191 (Generic Aging Lessons Learned (GALL)) programs and the PBN AMPs is shown below. Links to the sections describing the PBN NUREG-2191 programs are provided.

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	PBN Aging Management Program
X.M1	Fatigue Monitoring	Fatigue Monitoring (Section B.2.2.1)
X.M2	Neutron Fluence Monitoring	Neutron Fluence Monitoring (Section B.2.2.2)
X.S1	Concrete Containment Unbonded Tendon Prestress	Concrete Containment Unbonded Tendon Prestress (Section B.2.2.3)
X.E1	Environmental Qualification of Electric Equipment	Environmental Qualification of Electric Equipment (Section B.2.2.4)
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B.2.3.1)
XI.M2	Water Chemistry	Water Chemistry (Section B.2.3.2)
XI.M3	Reactor Head Closure Stud Bolting	Reactor Head Closure Stud Bolting (Section B.2.3.3)
XI.M4	BWR Vessel ID Attachment Welds	Not Applicable (PBN U1 and U2 are PWRs)
XI.M7	BWR Stress Corrosion Cracking	Not Applicable (PBN U1 and U2 are PWRs)
XI.M8	BWR Penetrations	Not Applicable (PBN U1 and U2 are PWRs)
XI.M9	BWR Vessel Internals	Not Applicable (PBN U1 and U2 are PWRs)
XI.M10	Boric Acid Corrosion	Boric Acid Corrosion (Section B.2.3.4)
XI.M11B	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs Only)	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (Section B.2.3.5)
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (Section B.2.3.6)
XI.M16A	PWR Vessel Internals	Reactor Vessel Internals (Section B.2.3.7)
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (Section B.2.3.8)
XI.M18	Bolting Integrity	Bolting Integrity (Section B.2.3.9)
XI.M19	Steam Generators	Steam Generators (Section B.2.3.10)
XI.M20	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (Section B.2.3.11)
XI.M21A	Closed Treated Water Systems	Closed Treated Water Systems (Section B.2.3.12)
XI.M22	Boraflex Monitoring	Not Applicable (PBN U1 and U2 do not credit Boraflex as a neutron absorber in their criticality analyses.)

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	PBN Aging Management Program
XI.M23	Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Inspection of Overhead Heavy Load Handling Systems (Section B.2.3.13)
XI.M24	Compressed Air Monitoring	Compressed Air Monitoring (Section B.2.3.14)
XI.M25	BWR Reactor Water Cleanup System	Not Applicable (PBN U1 and U2 are PWRs)
XI.M26	Fire Protection	Fire Protection (Section B.2.3.15)
XI.M27	Fire Water System	Fire Water System (Section B.2.3.16)
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks	Outdoor and Large Atmospheric Metallic Storage Tanks (Section B.2.3.17)
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry (Section B.2.3.18)
XI.M31	Reactor Vessel Material Surveillance	Reactor Vessel Material Surveillance (Section B.2.3.19)
XI.M32	One-Time Inspection	One-Time Inspection (Section B.2.3.20)
XI.M33	Selective Leaching	Selective Leaching (Section B.2.3.21)
XI.M35	ASME Code Class 1 Small-Bore Piping	ASME Code Class 1 Small-Bore Piping (Section B.2.3.22)
XI.M36	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components (Section B.2.3.23)
XI.M37	Flux Thimble Tube Inspection	Flux Thimble Tube Inspection (Section B.2.3.24)
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.3.25)
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis (Section B.2.3.26)
XI.M40	Monitoring of Neutron-Absorbing Materials other than Boraflex	Not Applicable (PBN U1 and U2 do not credit other neutron absorbers in their criticality analyses)
XI.M41	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks (Section B.2.3.27)
XI.M42	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.3.28)
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE (Section B.2.3.29)
XI.S2	ASME Section XI, Subsection IWL	ASME Section XI, Subsection IWL (Section B.2.3.30)
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF (Section B.2.3.31)
XI.S4	10 CFR Part 50, Appendix J	10 CFR 50, Appendix J (Section B.2.3.32)
XI.S5	Masonry Walls	Masonry Walls (Section B.2.3.33)
XI.S6	Structures Monitoring	Structures Monitoring (Section B.2.3.34)

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	PBN Aging Management Program
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section B.2.3.35)
XI.S8	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance (Section B.2.3.36)
XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements (Section B.2.3.37)
XI.E2	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits (Section B.2.3.38)
XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section B.2.3.39)
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section B.2.3.40)
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements (Section B.2.3.41)
XI.E4	Metal-Enclosed Bus	Metal-Enclosed Bus (Section B.2.3.42)
XI.E5	Fuse Holders	Not Applicable (PBN U1 and U2 do not have any components within the XI.E5 AMP scope.)
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements (Section B.2.3.43)
XI.E7	High-Voltage Insulators	High-Voltage Insulators (Section B.2.3.44)

Table B-4
Point Beach Aging Management Program Consistency with NUREG-2191

PBN Aging Management Program	Section	PBN Plant-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
Fatigue Monitoring	B.2.2.1	No	X.M1	Yes	No
Neutron Fluence Monitoring	B.2.2.2	No	X.M2	Yes	No
Concrete Containment Unbonded Tendon Prestress	B.2.2.3	No	X.S1	Yes	No
Environmental Qualification of Electric Equipment	B.2.2.4	No	X.E1	Yes	No
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B.2.3.1	No	XI.M1	No	No
Water Chemistry	B.2.3.2	No	XI.M2	No	Yes
Reactor Head Closure Stud Bolting	B.2.3.3	No	XI.M3	Yes	Yes
Boric Acid Corrosion	B.2.3.4	No	XI.M10	Yes	No
Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	B.2.3.5	No	XI.M11B	Yes	No
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel	B.2.3.6	No	XI.M12	New	No
Reactor Vessel Internals	B.2.3.7	No	XI.M16A	Yes	Yes
Flow-Accelerated Corrosion	B.2.3.8	No	XI.M17	Yes	No
Bolting Integrity	B.2.3.9	No	XI.M18	Yes	No
Steam Generators	B.2.3.10	No	XI.M19	Yes	Yes
Open-Cycle Cooling Water System	B.2.3.11	No	XI.M20	Yes	Yes
Closed Treated Water Systems	B.2.3.12	No	XI.M21A	Yes	Yes
Inspection of Overhead Heavy Load Handling Systems	B.2.3.13	No	XI.M23	Yes	No

Table B-4
Point Beach Aging Management Program Consistency with NUREG-2191

PBN Aging Management Program	Section	PBN Plant-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
Compressed Air Monitoring	B.2.3.14	No	XI.M24	Yes	No
Fire Protection	B.2.3.15	No	XI.M26	Yes	No
Fire Water System	B.2.3.16	No	XI.M27	Yes	No
Outdoor and Large Atmospheric Metallic Storage Tanks	B.2.3.17	No	XI.M29	Yes	No
Fuel Oil Chemistry	B.2.3.18	No	XI.M30	Yes	Yes
Reactor Vessel Material Surveillance	B.2.3.19	No	XI.M31	No	Yes
One-Time Inspection	B.2.3.20	No	XI.M32	Yes	No
Selective Leaching	B.2.3.21	No	XI.M33	New	No
ASME Code Class 1 Small-Bore Piping	B.2.3.22	No	XI.M35	Yes	No
External Surfaces Monitoring of Mechanical Components	B.2.3.23	No	XI.M36	Yes	No
Flux Thimble Tube Inspection	B.2.3.24	No	XI.M37	Yes	No
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B.2.3.25	No	XI.M38	New	No
Lubricating Oil Analysis	B.2.3.26	No	XI.M39	Yes	No
Buried and Underground Piping and Tanks	B.2.3.27	No	XI.M41	Yes	Yes
Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B.2.3.28	No	XI.M42	New	Yes
ASME Section XI, Subsection IWE	B.2.3.29	No	XI.S1	Yes	No
ASME Section XI, Subsection IWL	B.2.3.30	No	XI.S2	Yes	No
ASME Section XI, Subsection IWF	B.2.3.31	No	XI.S3	Yes	Yes
10 CFR Part 50, Appendix J	B.2.3.32	No	XI.S4	No	No
Masonry Walls	B.2.3.33	No	XI.S5	Yes	No

Table B-4
Point Beach Aging Management Program Consistency with NUREG-2191

PBN Aging Management Program	Section	PBN Plant-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
Structures Monitoring	B.2.3.34	No	XI.S6	Yes	No
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B.2.3.35	No	XI.S7	Yes	No
Protective Coating Monitoring and Maintenance	B.2.3.36	No	XI.S8	Yes	No
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.37	No	XI.E1	Yes	No
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements used in Instrumentation Circuits	B.2.3.38	No	XI.E2	Yes	No
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.39	No	XI.E3A	Yes	No
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.40	No	XI.E3B	New	No
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.41	No	XI.E3C	New	No
Metal-Enclosed Bus	B.2.3.42	No	XI.E4	New	No

Table B-4
Point Beach Aging Management Program Consistency with NUREG-2191

PBN Aging Management Program	Section	PBN Plant-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements	B.2.3.43	No	XI.E6	New	No
High-Voltage Insulators	B.2.3.44	No	XI.E7	New	No

B.2.2 NUREG-2191 Chapter X Aging Management Programs

This section provides summaries of the NUREG-2191 Chapter X AMPs credited for managing the effects of aging at PBN.

B.2.2.1 Fatigue Monitoring

Program Description

The PBN Fatigue Monitoring AMP is an existing AMP that provides an acceptable basis for managing fatigue of components that are the subject to fatigue or cycle-based time-limited aging analyses (TLAAs) or other analyses that assess fatigue or cyclical loading.

Examples of cycle-based fatigue analyses for which this AMP is used include, but are not limited to: (a) cumulative usage factor (CUF) analyses or their equivalent that are performed in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) requirements for specific mechanical components; (b) fatigue analysis calculations for assessing environmentally assisted fatigue (EAF); (c) implicit fatigue analyses, as defined in the American National Standards Institute (ANSI) B31.1 design code or ASME Code Section III rules for Class 2 and 3 components; (d) fatigue flaw growth analyses that are based on cyclical loading assumptions; and (e) fracture mechanics analyses that are based on cycle-based loading assumptions.

The PBN Fatigue Monitoring AMP verifies the continued acceptability of existing analyses through manual cycle counting for monitoring CUF for the selected component locations using cycle based fatigue monitoring.

The program provides reasonable assurance that the number of occurrences of each design transient remains within the limits of the component fatigue analyses, which in turn provides reasonable assurance that the analyses remain valid. CUF is a computed parameter used to assess the likelihood of fatigue damage in components subjected to cyclic stresses. Crack initiation is assumed to begin in a mechanical component when the CUF at a point on or in the component reaches the value of 1.0, which is the ASME Code Section III design limit on CUF values. In order not to exceed the design limit on CUF, the procedures that implement the AMP monitor the number of transient occurrences (i.e., design cycles). SLRA Section 4.3 provides details of the evaluation of fatigue for PBN components that have a calculated CUF. SLRA Table 4.3.1-1 identify the PBN design cycles utilized in these component fatigue analyses and concludes that the projected cycles through the SPEO will not exceed the design cycles assumed in the analyses.

CUF_{en} is CUF adjusted to account for the effects of the reactor water environment on component fatigue life. For PBN to ensure that all potential limiting component locations are captured, all the reactor coolant pressure boundary components with existing ASME Code fatigue analyses, including those PBN site-specific NUREG/CR-6260 locations, have been evaluated for EAF. SLRA Section 4.3.4 provides details of the evaluation for environmentally assisted fatigue for the PBN SPEO. The effects of fatigue on the intended functions of the ASME Code, Section III components and B31.1 piping components listed in Table 4.3.4-1 that have a calculated CUF_{en} value less than 1.0 will be managed by this AMP through the use of cycle counting and taking required actions prior to exceeding design limits that would invalidate their conclusions.

For the pressurizer spray nozzle safe ends, the effects of fatigue will be managed by application of the In-service Inspection program (ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1) during the SPEO based on results of flaw tolerance evaluation conducted in accordance with the guidance of ASME Code, Section XI, Nonmandatory, Appendix L. NUREG-2192 permits inspections as a management method for fatigue as long as a flaw tolerance evaluation is performed to determine the acceptable time between inspections. The ASME Code, Section XI, Appendix L crack growth evaluation is used in conjunction with calculated allowable flaw sizes to determine the required inspection interval for a postulated flaw in the piping at the bounding location. For a postulated initial flaw, crack growth is simulated until the flaw has reached the allowable flaw depth or the end of the SPEO, whichever comes first.

For the steam generator primary side tube location, the effects of fatigue will be managed by the Steam Generators AMP (Section B.2.3.10). Consistent with the GALL-SLR Report AMP XI.M19, the steam generator tubes will be volumetrically examined such that fatigue cracks will be detected, and corrective actions will be initiated as appropriate to maintain the intended functions.

The PBN Fatigue Monitoring AMP provides for corrective actions when any actual transient cycle count approaches the design or projected cycle limit. Plant management is notified in accordance with the program procedural requirements, and the condition is entered into the CAP. Under these circumstances, component reevaluation, enhanced inspection, repair or replacement is required to demonstrate that the fatigue design limit will not be exceeded during the SPEO.

NUREG-2191 Consistency

The PBN Fatigue Monitoring AMP, with enhancements will be consistent with the 10 elements of NUREG-2191, Section X.M1, “Fatigue Monitoring.”

Exceptions to NUREG-2191

None.

Enhancements

The PBN Fatigue Monitoring AMP requires the following enhancements to be implemented for no later than six months prior to the SPEO to be consistent with NUREG-2191 Section X.M1.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Update the AMP governing procedure to monitor the chemistry parameters that provide inputs to F_{en} factors used in CUF_{en} calculations. These chemistry parameters include dissolved oxygen and sulfate and are controlled and tracked in accordance with the PBN Water Chemistry AMP.
3. Parameters Monitored or Inspected	Update the AMP governing procedure to identify and require monitoring of the 80-year plant design cycles, or projected cycles that are utilized as inputs to component CUF_{en} calculations, as applicable.
5. Monitoring and Trending	Update the AMP governing procedure to identify the corrective action options if the values assumed for fatigue parameters are approached, transient severities exceed the design or assumed severities, transient counts exceed the design or assumed quantities, transient definitions have changed, unanticipated new fatigue loading events are discovered, or the geometries of components are modified.

Operating Experience

Industry Operating Experience

PBN evaluates industry OE items for applicability per the NextEra Fleet OE Program and takes corrective actions, when necessary. For example:

- Recent domestic and international fatigue test data show that the light water reactor (LWR) environment can have a significant impact on the fatigue life of carbon and low-alloy steels, austenitic stainless steel, and nickel-chromium-iron (Ni-Cr-Fe) alloys. NRC Regulatory Guide (RG) 1.207 describes the methods that the staff considers acceptable for use in performing fatigue evaluations, considering the effects of LWR environments on carbon and low-alloy steels, austenitic stainless steels, and Ni-Cr-Fe alloys. Specifically, these methods include calculating the fatigue usage in air using ASME Code analysis procedures, and then employing the environmental correction factor (F_{en}), as described in NUREG/CR-6909. As discussed in SLRA Section 4.3.4, the methodology described in NUREG/CR-6909, Revision 1 was utilized in calculating the PBN F_{ens} for the SPEO.

- NRC Regulatory Issue Summary 2008-30, “Fatigue Analysis of Nuclear Power Plant Components” was issued to address a concern regarding the methodology used by some license renewal applicants to demonstrate the ability of nuclear power plant components to withstand the cyclic loads associated with plant transient operations for the period of extended operation. This particular analysis methodology involves the use of the Green’s (or influence) function to calculate the fatigue usage during plant transient operations such as startups and shutdowns. PBN did use this methodology and performed an ASME Code Section III, Subsection NB, Subarticle NB-3200 analysis for the charging nozzle and hot leg surge nozzle consistent with the requirements in RIS 2008-30.

- NRC Regulatory Issue Summary 2011-14, “Metal Fatigue Analysis Performed by Computer Software” was issued to address concerns with using computer software packages to demonstrate compliance with Section III, “Rules for Construction of Nuclear Facility Components,” of the ASME Code. RIS 2011-14 addressed several issues that arose during an NRC audit of the AP1000 plant analysis performed using WESTEMS computer software with follow-up audits of the application of the software in design and monitoring modes for the Salem license renewal application. This RIS 2011-14 does not affect work performed by FatiguePro used by PBN since FatiguePro does not perform analyses using NB 3600 rules and does not allow user intervention in the determination of time histories.

- EPRI Material Reliability Program (MRP) Technical Report MRP-146, “Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines,” which replaced MRP-24, provides guidelines and other good practice recommendations for evaluating and inspecting regions in normally stagnant PWR reactor coolant system (RCS) branch lines where there may be the potential for thermal fatigue cracking. An engineering evaluation was completed to document the thermal cycle screening and identify further evaluations/examinations required of non-isolable PBN reactor coolant system (RCS) branch piping greater than one inch in diameter per the guidance provided in MRP-132, “Thermal Cycling Screening and Evaluation Model for Normally Stagnant Non-Isolable Reactor Coolant Branch Line Piping With a Generic Application Assessment.”

  The 10" residual heat removal (RHR) suction lines for PBN Units 1 and 2 did not screen out per MRP-146. These lines were examined during subsequent refueling outages and no thermal fatigue cracking was identified in either line.

  Structural Integrity Associates completed an MRP-146S scoping evaluation for the screened-in Unit 1 and Unit 2 RHR suction lines. Based on the scoping evaluation, a fatigue evaluation for the screened-in RHR suction lines using conservative assumptions was not recommended. This conclusion is based on the estimated minimum stratification ΔT likely to be determined using more detailed analysis compared to the maximum stratification ΔT that would result in a CUF ≤ 0.7. Implementation of the MRP-146 Revision 1 inspection frequency of every other cycle for screened-in lines was recommended to avoid further analysis. These examinations were added to the inservice inspection schedule.

- EPRI Materials Reliability Program (MRP) MRP-192, "Assessment of RHR Mixing Tee Thermal Fatigue in PWR Plants" provides good practice guidelines and recommendations for evaluating and inspecting RHR mixing tees where there may be the potential for thermal fatigue cracking. This cracking could lead to leakage and forced plant outages.

  An engineering evaluation was performed to assess the PBN RHR mixing tee locations and provide an action plan to address the MRP-192 recommendations. The Unit 1 and Unit 2 RHR heat exchanger bypass lines have butterfly control valves and the RHR pump minimum bypass lines have stop valves which are normally open. These conditions would allow hot and cold water to simultaneously enter the mixing tee, resulting in thermal stratification and fatigue cracking. Inspections of the corresponding mixing tee locations were completed during subsequent refueling outages and no thermal fatigue cracking was identified.

The examples above demonstrate that the PBN Fatigue Monitoring AMP reviews and incorporates applicable industry OE into the program. This provides reasonable assurance that the Fatigue Monitoring AMP will continue to be effective during the SPEO.

Plant Specific Operating Experience

Identified Action Request from July 19, 2013:

A PBN review of a draft WCAP prepared by Westinghouse related to reactor vessel internals baffle-barrel bolting indicated that changes were recommended to UFSAR table 4.1-8 “Thermal and Loading Cycles.” Details from a Westinghouse corrective action report indicated that there was a potential error in a calculation prepared for the PBN EPU due to the use of an incorrect fatigue curve. The FSAR table lists the number of design cycles that are allowable for the 60-year life of the plant. As a result of the action request disposition, some of allowable design cycle values were reduced, but none of them were predicted to be exceeded by the end of life for the units. The affected design cycles were Unit Loading/Unloading, Step Load Increase, Step Load Decrease, Large Step Load Decrease, Loss of Load, Loss of Power, Loss of Flow, and Reactor trip. These values are monitored under the Fatigue Monitoring Program and project actual plant cycles based on operating history. This issue represents a reduction in allowable design cycles; however, all projected cycles are well below the reduced allowable design values.

Based upon review of the action request, the issue identified did not impact the ability of the reactor coolant system to perform its intended functions and was therefore determined to be fully operable. The use of the incorrect curve did reduce the total number of design cycles allowed for the units, but the total number of projected cycles of the units will not approach the allowable. The reduced number of allowable design cycles are still in excess of two times the number of projected cycles.

Identified Action Request from February 20, 2020:

The two year aging management interim effectiveness review identified that due to turnover of personnel, the program needed to be assigned to a new owner who is knowledgeable/proficient with this program.

PBN contracted with Structural Integrity Associates, Inc., (SIA) to review the FatiguePro program and received an updated report that incorporated FatiguePro data through 2019 for 80-year life projections.

Going forward, PBN will no longer use FatiguePro and instead will use the manual count method.

Additional actions associated with this AR include identifying/assigning an in-house fatigue monitoring program owner. A subsequent activity was initiated to track completion of the Aging Management Program Owner qualifications per procedural requirements once a new owner is identified.

The following reviews were conducted either as self-assessments or NRC post-approval reviews. No review identified any issues with the effectiveness of the Fatigue Monitoring AMP:

Phase 2 Point Beach Nuclear Plant, Units 1 and 2 NRC Post-Approval Site Inspection Report for License Renewal:

The NRC reviewed the licensing basis, program basis document, implementing procedures, NDE records, and related CRs; and interviewed the plant personnel responsible for the AMPs. The NRC verified that program implementing documents contained the appropriate License Renewal references. The inspectors verified that the program and enhancements were in place to ensure that inspections for the applicable aging effects were performed and any noted indications were appropriately evaluated.

The inspectors also reviewed the licensee’s evaluation of external operating experience related to Regulatory Issue Summary 2008-30, “Fatigue Analysis of Nuclear Power Plant Components,” dated December 16, 2008, including the confirmatory analyses performed to demonstrate that the fatigue cumulative usage factors, calculated using six components of the stress tensor in accordance with Subsection NB of the ASME code, were less than one for plant operation through the period of extended operation.

An effectiveness review of the Fatigue Monitoring AMP was performed in 2018 as part of the License Renewal Aging Management Program Effectiveness Review following the guidelines provided in NEI 14-12. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (Element 4), corrective action (Element 7), and operating experience (Element 10). The effectiveness review found that PBN Fatigue Monitoring AMP continued to be effectively implemented. Although there were several observations, they have all since been resolved.

Phase 4 Point Beach Nuclear Plant, Units 1 and 2 NRC Post-Approval Site Inspection Report for License Renewal

The NRC did not identify any finding or violation of more-than-minor significance. The Fatigue Monitoring AMP was not one of the 7 AMPs selected during the Phase 4 inspection.

To date, no enhancements to the AMP have been identified as a result of OE. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Fatigue Monitoring AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Fatigue Monitoring AMP, with enhancements, will provide reasonable assurance that aging effects will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.2.2 Neutron Fluence Monitoring

Program Description

The PBN Neutron Fluence Monitoring AMP, previously the fluence and uncertainty calculation portion of the PBN Reactor Vessel Material Surveillance Program, is an existing program providing reasonable assurance of the continued validity of the neutron fluence analyses and neutron fluence-based TLAA and related analyses involving time-dependent neutron irradiation through monitoring and periodic updates. In so doing, this AMP also provides an acceptable basis for managing aging effects attributable to neutron fluence irradiation in accordance with requirements in 10 CFR 54.21(c)(1)(iii). This AMP monitors neutron fluence for reactor pressure vessel (RPV) and reactor vessel internals (RVI) components and is used in conjunction with the PBN Reactor Vessel Material Surveillance AMP.

Neutron fluence is considered to be a TLAA and is a time-dependent input to a number of RPV irradiation embrittlement (IE) analyses that are required by specific regulations in 10 CFR Part 50 for demonstration of RPV integrity. These analyses are the TLAAs for SLR and are the topic of the acceptance criteria and review procedures in NUREG-2192, Section 4.2, "Reactor Vessel Neutron Embrittlement Analyses." The neutron IE TLAA in the scope of this AMP include:

- Neutron fluence.
- Pressurized thermal shock (PTS), as required by 10 CFR 50.61.
- Upper-shelf energy (USE) and associated equivalent margins analyses (EMA), as required by Section IV.A.1 of 10 CFR Part 50, Appendix G.
- Pressure-temperature (P-T) curves.

Guidance on acceptable methods and assumptions for determining reactor vessel neutron fluence is described in NRC RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," which originated as Draft Regulatory Guide (DG)-1053 (Reference ML993350434). The methods developed and approved using the guidance contained in RG 1.190 are specifically intended to determine neutron fluence in the cylindrical region of the RPV surrounding the effective height of the active fuel.

This AMP evaluates the RPV surveillance capsule dosimetry data and updates the fluence projections in the cylindrical RPV locations, as needed. The Westinghouse Commercial Atomic Power (WCAP)-16083-NP-A (Reference ML061600256) methodology (equivalent to WCAP-14040-A), which complies with RG 1.190, in conjunction with WCAP-18124-NP-A (Reference ML18204A010) is used for PBN fluence determinations in the cylindrical RPV region that surrounds the effective height of the active fuel, the RPV beltline. Calculational methods, benchmarking, qualification, and surveillance data are monitored to maintain the adequacy and ascribed uncertainty of RPV beltline neutron fluence calculations and thereby the associated RPV IE analyses:

- This approved methodology uses geometrical and material input data, and equilibrium fuel cycle operational data, to determine characteristics of the neutron flux in the core.

- Additionally, these data are used to determine the neutron transport to the vessel and into the reactor cavity.
- Capsule surveillance data is used for qualification of the neutron fluence calculation.
- The same WCAP-16083-NP-A methodology was used for the fluence calculations performed in support of the PBN Unit 1 and Unit 2 extended power uprates (EPUs).

In addition, neutron fluence is a time-dependent input parameter for evaluating the loss of fracture toughness of RVI components due to neutron IE, irradiation-assisted stress corrosion cracking (IASCC), irradiation-enhanced stress relaxation and creep and void swelling (VS) or distortion.

Neutron fluence estimates are also necessary for the definition of the (extended) RPV beltline region, RPV locations above (or below) the effective height of the active fuel that are projected to exceed 1 x 10^{17} n/cm^2 (E > 1 MeV) during the SPEO, as defined in RIS 2014-11 (Reference ML14149A165), "Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components."

The WCAP-16083-NP-A methodology, in conjunction with WCAP-18124-NP-A was also used to estimate conservative neutron fluence for the RPV locations above and below the effective height of the active fuel for SLR. PBN follows related industry efforts, such as those from the Pressurized Water Reactor Owners Group (PWROG) and will use the information from those efforts to provide additional justification for fluence determinations in those areas prior to entering the SPEO.

Neutron fluence calculations are updated periodically, such as in support of related licensing actions and surveillance capsule information, to ensure that the plant and core operating conditions remain consistent with the assumptions used in the neutron fluence analyses and that the related analyses are updated as necessary.

There are no specific acceptance criteria values for neutron fluence; the acceptance criteria relate to the different parameters that are evaluated using neutron fluence. NRC RG 1.190 provides guidance for acceptable methods to determine neutron fluence for the RPV (effective height of the active fuel) beltline region. Applying NRC RG 1.190-adherent methods to determine neutron fluence in locations other than those close to the active fuel region of the core warrants additional justification.

Prior to entering the SPEO, PBN will follow the related industry efforts, such as by the PWROG, and will use the information or other information to provide additional justification for use of the WCAP-16083-NP-A and WCAP-18124-NP-A or similar methodology for the estimate of RPV nozzle location fluence. This further justification will draw from Westinghouse's NRC approved RPV fluence calculation methodology, and will include discussion of the neutron source, synthesis of the flux field and the order of angular quadrature (e.g., S8), etc. used in the estimates for projection of TLAA to 80 years.

NUREG-2191 Consistency

The PBN Neutron Fluence Monitoring AMP, with enhancements, will be consistent with the 10-elements of NUREG-2191, Section X.M2, “Neutron Fluence Monitoring” as modified by SLR-ISG-Mechanical-2020-XX, Updated aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance.

Exceptions to NUREG-2191

None.

Enhancements

The following enhancements will be implemented no later than six months prior to entering the SPEO. There are no new inspections to be implemented for SLR.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Follow the related industry efforts, such as by the PWROG, and use the information from supplemental nozzle region dosimetry measurements and reference cases or other information to provide additional justification for use of the WCAP-16083-NP-A in conjunction with WCAP-18124-NP-A or similar methodology for the estimate of RPV fluence in regions above or below the active fuel region.
6. Acceptance Criteria	Draw from Westinghouse’s NRC approved fluence calculation methodology and include discussion of the neutron source, synthesis of the flux field and the order of angular quadrature (e.g., S8), etc. used in the estimates for projection of TLAAs to 80 years in the additional justification of RPV fluence in regions other than active fuel region.

Operating Experience

Industry Operating Experience

Recent industry licensing actions that affect plant life and/or power level, include consideration of fluence in adjacent RPV regions outside the effective height of the active fuel to confirm that RPV limiting components, relative to embrittlement and pressure-temperature limits, are those that surround the effective height of the active fuel; through demonstrating that:

- RPV nozzle fluence determinations are conservative (Reference ML15096A324) or
- Nozzle regions will experience a fluence less than $1x10^{17}$ n/cm^2 at the end of license/life (Reference ML16081A333).

RPV nozzle belt fluence was also addressed for original license renewal. PBN licensing actions that impact CLB information consider the following:

- Recent utility licensing submittals.
- Recent NRC safety evaluations (SEs).
- Recent NRC requests for additional information (RAIs).
- Recent utility responses.

Plant Specific Operating Experience

The RPV beltline neutron fluence and uncertainty calculations for PBN Units 1 and 2 have been performed in accordance with the guidelines of the RG 1.190 and validated using data obtained from capsule dosimetry. The results of the fluence uncertainty values to date are within the NRC-suggested limit of ±20 percent. RPV beltline fluence determinations support the RPV IE analyses documented in the CLB, including update and confirmation to EPU and P-T limit curve updates.

This methodology represents a continuous validation process to ensure that no biases have been introduced for limiting RPV beltline locations, and that the uncertainties in those locations remain comparable to the reference benchmarks upon which RPV embrittlement analyses, that demonstrate continued RPV integrity, are based.

An error was identified in 2019 concerning calculation of the lead factor (ratio of capsule fluence compared to the maximum vessel fluence). However, the capsule removal schedule approved by the NRC was based on the actual surveillance capsule fluence projection and not the lead factor. Thus, there was no impact to the capsule removal schedule.

In 2018, an effectiveness review was performed following the guidelines provided in NEI 14-12, Aging Management Program Effectiveness. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (Element 4), corrective action (Element 7), and operating experience (Element 10). The effectiveness review found that this program continues to be effectively implemented.

To date, no enhancements to the AMP have been identified as a result of operating experience. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Neutron Fluence Monitoring AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Neutron Fluence Monitoring AMP, with enhancements, will provide reasonable assurance that applicable RPV neutron irradiation embrittlement analyses (i.e. TLAAs), that demonstrate RPV integrity, and radiation-induced aging effect assessments for RVI components will remain within their applicable limits reported in the CLB during the SPEO. The PBN Neutron Fluence Monitoring AMP, in conjunction with the PBN Reactor Vessel Material Surveillance AMP, will also provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of these AMPs will be maintained consistent with the CLB during the SPEO.

B.2.2.3 Concrete Containment Unbonded Tendon Prestress

Program Description

PBN Concrete Containment Unbonded Tendon Prestress AMP is an existing condition monitoring AMP. The purpose of this AMP is to provide reasonable assurance of the continued adequacy of prestressing forces in the unbonded tendons for the pre-stressed concrete containments through the SPEO. Loss of containment tendon prestressing forces is a TLAA that has been projected to the end of the SPEO. For completeness, the PBN Concrete Containment Unbonded Tendon Prestress AMP serves to confirm continued validity of the prestress force projections through the end of the SPEO, a 10CFR54.21(c)(1)(iii) disposition.

Measurement and assessment of tendon prestress forces, in comparison to lower bound predictions and (minimum) required force, comprise the AMP. Tendon prestress forces are periodically measured during “physical” inspections, concurrent with other required inspections by the PBN ASME Section XI, Subsection IWL AMP. The PBN Concrete Containment Unbonded Tendon Prestress AMP is a confirmatory program for SLR that monitors the loss of containment tendon prestressing forces throughout the life of the plant for each tendon group (i.e., dome, hoop and vertical) to ensure that the trend lines of the measured prestressing forces remain above the (minimum) required force before the next scheduled inspection. Otherwise, corrective actions are taken to ensure containment prestress adequacy. Upper and lower bounds and regression trends are assessed based on the guidance of Nuclear Regulatory Commission (NRC) Information Notice (IN) 99-10, “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments” (Reference ML031500244) and Regulatory Guide (RG) 1.35.1 for calculating prestressing losses and predicted forces.

The PBN Concrete Containment Unbonded Tendon Prestress AMP is part of the Pre-Stressed Concrete Containment Tendon Surveillance Program described in Technical Requirements Manual (TRM) 4.17 and Technical Specification (TS) 5.5.17.

NUREG-2191 Consistency

The PBN Concrete Containment Unbonded Tendon Prestress AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section X.S1, “Concrete Containment Unbonded Tendon Prestress.”

Exceptions to NUREG-2191

None.

Enhancements

The following enhancements will be implemented no later than six months prior to entering the SPEO. There are no new inspections to be implemented for SLR.

Element Affected	Enhancement
5. Monitoring and Trending	Formalize the update of prestress calculations and trend lines after each scheduled “physical” inspection, which includes monitoring of tendon forces, in accordance with RG 1.35.1.
6. Acceptance Criteria	Include the 80-year prestress calculation with or in place of the current, 60-year, acceptance limits in the program plan for each IWL inspection interval.

Operating Experience

Industry Operating Experience

External (industry) operating experience is evaluated through the action request (AR), initial screening for the CR, process to confirm applicability to Point Beach or identify the appropriate adjustments / improvements to the AMP. There has been limited industry operating experience since entering the period of extended operation, in October of 2010, that address tendon prestress calculations apart from the ASME XI, Subsection IWL considerations.

Low prestress force instances described in NUREG/CR-7111 and IN 99-10 were attributed to a) high tendon wire relaxation, as a result of elevated temperature effects, or b) broken wires, in tendons that were replaced. For Point Beach, the net effect of elevated temperatures on tendons in the vicinity of the Unit 2 main steam and feedwater containment penetrations were addressed in NUREG-1839 (pgs 3-275, 3-276) and the Point Beach response to RAI 3.5-3 associated with the current renewed licenses. The hoop tendons’, one above and one below the subject penetration, exposure to higher temperature occurred over a relatively short length of time and was determined to present a negligible effect on tendon prestress. With regard to item b), only one tendon has been replaced at PBN. A Unit 2 dome tendon was replaced in 1979 during the eighth-year surveillance. However, no surveillance instances of low prestress forces could be identified that were attributed to broken wires in that tendon.

Plant Specific Operating Experience

New common tendons, which had not been previously detensioned and retensioned, were selected for the 28th year surveillance in 1999. There have been four (4) tendon surveillances since the 28th year, with Unit 2 receiving the most recent “physical” inspection in 2019. The random tendon selection for years 48 to 73 has been established/planned, including identification of former and current common (control) tendons. In addition, engineering review of the randomly selected containment tendon plan prior to a given tendon surveillance ensures that tendons previously detensioned and retensioned from the 1st year to 23rd year surveillance are not assigned as control tendons.

The same vendor that provided the 28th year tendon surveillance has provided each subsequent surveillance (33rd, 38th, 43rd and 48th), with reports provided and non-conformances identified for each surveillance. The most recent, 48th-year, tendon surveillance in 2019 involved a “visual” inspection of Unit 1 and a “physical” inspection of Unit 2 randomly selected and common tendons with acceptable prestress force results. In addition, identified non-conformances or related action requests are associated with conditions such as grease leakage, button head, and/or broken wire considerations that are germane to the PBN ASME Section XI, Subsection IWL AMP, rather than a loss of prestress. Refer to Section B.2.3.30 for operating experience related to ASME Section XI, Subsection IWL inspections.

The tendon surveillance reports since the 1st year (1st, 3rd, 8th, 13th, 18th, 23rd, and 28th) are also available and have been considered in periodic updates of the predicted prestress force trends.

In 2018, an effectiveness review was performed following the guidelines provided in NEI 14-12, Aging Management Program Effectiveness. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (Element 4), corrective action (Element 7), and operating experience (Element 10). The effectiveness review found that this program continues to be effectively implemented.

OE will be reviewed such that if there is an indication that the aging effects are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Concrete Containment Unbonded Tendon Prestress AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Concrete Containment Unbonded Tendon Prestress AMP, with enhancements, and in conjunction with the PBN ASME Section XI, Subsection IWL AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.2.4 Environmental Qualification of Electric Equipment

Program Description

The PBN Environmental Qualification of Electric Equipment AMP is an existing AMP, previously the Environmental Qualification (EQ) Program, that manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. The NRC has established nuclear station EQ requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants.”

This AMP provides the requirements for the environmental qualification of electrical equipment important to safety that could be exposed to harsh environment accident conditions as required by 10 CFR 50.49 and RG 1.89, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants." This AMP is established per the requirements of 10 CFR 50.49 to demonstrate that certain electrical components located in harsh plant environments (i.e., 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 a main steam line break (MSLB) inside or outside the containment, from elevated temperatures or high radiation or steam, or their combination) are qualified to perform their safety function in those harsh environments after the effects of inservice (operational) aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ, and that the equipment be demonstrated to function in the harsh environment, following aging.

The preventive actions associated with this AMP include the identification of qualified life and specific maintenance/installation requirements to maintain the component within the qualification basis. This AMP provides EQ-related surveillance and maintenance requirements for EQ equipment and monitoring, or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life. Although 10 CFR 50.49 does not require monitoring and trending of EQ equipment, this AMP does provide surveillance and maintenance requirements for the EQ equipment, verifies that the required activities are performed, and tracks and maintains the service life of qualified components. Implementation of this AMP is a coordinated effort from a variety of departments within the PBN and fleet organization to ensure the continued environmental integrity of specified equipment to remain operable when exposed to a harsh environment. Surveillance and maintenance are performed on all equipment on the EQ list to ensure the equipment remains qualified. The PBN EQ of Electric Equipment AMP will also provide for visual inspection of accessible, passive EQ equipment at least once every 10 years (see Enhancement statement, below). This inspection is performed to view the EQ equipment, and also to identify any adverse localized plant environments. An adverse localized environment is an environment that exceeds the most limiting qualified condition for temperature or radiation for the component material. An adverse localized environment may increase the rate of aging or have an adverse effect on the basis for equipment qualification. EQ electrical equipment may degrade more rapidly than expected when exposed to an adverse localized environment.

If monitoring is used to modify a component's qualified life, then appropriate plant-specific acceptance criteria will be established based on applicable 10 CFR 50.49(f) qualification methods. Visual inspection results will show that accessible passive EQ equipment is free from unacceptable surface abnormalities that may indicate age degradation. An unacceptable indication is defined as a noted condition or situation, that if left unmanaged, could potentially lead to a loss of intended function.

When analysis cannot justify a qualified life in excess of the original PEO and up to the end of the SPEO, then the component parts will be replaced, refurbished, or requalified prior to exceeding the qualified life as required by 10 CFR 50.49. Re-analysis of an aging evaluation addresses attributes of analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. The PBN Environmental Qualification documentation packages (referred to as Equipment Qualification Checklists [EQCK]) are considered time-limited aging analyses (TLAAs) per 10 CFR 54.21(c)(1).

NUREG-2191 Consistency

The PBN Environmental Qualification of Electric Equipment AMP, with an enhancement, will be consistent with the 10 elements of NUREG-2191, Section X.E1, “Environmental Qualification of Electric Equipment.”

Exceptions to NUREG-2191

None.

Enhancements

The PBN Environmental Qualification of Electric Equipment AMP will be enhanced per the following table for alignment with NUREG-2191 and to capture SLR commitments. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Visually inspect accessible, passive EQ equipment for adverse localized environments that could impact qualified life at least once every 10 years with the first periodic visual inspection being performed prior to the SPEO.

Operating Experience

Industry Operating Experience

Industry operating experience on Environmental Qualification covers a long period of time, dating back to the 1970s. Every nuclear plant has an EQ program, and the NUGEQ (Nuclear Utility Group on Equipment Qualification) was founded in 1981 to bring the licensees together in order to share lessons learned on EQ, to provide input on EQ technical and licensing issues, and to create a forum for learning, as the NRC began to expand on EQ rulemaking after the TMI-2 event. With respect to the fleet, there is an EQ program owner and an assigned EQ support engineer at the various sites, including PBN. These individuals receive and address (if necessary) the industry OE on EQ (from other plants, from NRC, and from external industry guidance, such as NUGEQ) and also address industry technical issues regarding EQ components (e.g., 10 CFR Part 21 Notifications on EQ equipment, and other component vendor reports / circulars / bulletins).

In recent years, licensees (those that have completed the License Renewal process from 40-to-60 years) have been focused on updating their EQ programs to reflect the new plant lifetime of 60 years. PBN completed this effort shortly after receiving its renewed license, around 2005/2006. Other industry issues have involved component upgrades (replacement of older model equipment with newer models, such as Rosemount 3154N transmitters replacing older 1153 and 1154 models). While these items are not typically thought of as industry OE, they are discussed among the licensees and are topics of discussion at industry meetings (such as the annual NUGEQ meeting). In the NUGEQ meeting held in Nov. 2017, one topic discussed was the EQ DBA (Design Basis Assurance) Inspections being conducted by the NRC. The licensees covered the topics brought out during individual plant EQ DBA inspections (in 2017) and learned what issues/problems were identified. A NEE fleet representative attended this meeting. The PBN Environmental Qualification Electric Equipment program is informed by these meetings, and also by addressing generic industry EQ issues from the NRC or other organizations. The incorporation of industry OE into the PBN Environmental Qualification of Electric Equipment program is highlighted in PBN EQ implementing procedure.

<u>Plant Specific Operating Experience</u>

The following examples of OE provide objective evidence that the PBN Environmental Qualification of Electric Equipment program will be effective in ensuring that component intended functions are maintained consistent with the CLB during the SPEO.

A review of quarterly system health reports covering the period from the first quarter (Q1) of 2015 through Q1 2020 was conducted to determine program performance during the PEO. The EQ program health report is currently GREEN and has shown green for several quarters.

In 2010 and 2013, the NRC examined activities conducted under PBN's Unit 1 and Unit 2 renewed operating licenses, respectively, as they relate to safety and compliance with the Commission's rules and regulations under the conditions of the renewed operating licenses.

The NRC reviewed the licensing basis, program basis document, implementing procedures, assessments, and related condition reports (CRs); and interviewed the plant personnel responsible for the PBN Environmental Qualification of Electric Equipment program. The NRC also reviewed the self-assessment reports completed in 2006 and 2010, and the corrective actions resulting from these assessments. The NRC verified that program implementing documents contain the appropriate License Renewal references. The NRC verified that PBN had conducted an assessment of all EQ components which include field verification and completion of EQ checklist reviews, which evaluates operating experience.

Based on the review of the timeliness and adequacy of PBN's actions, the NRC concluded that the PBN Environmental Qualification of Electric Equipment program commitments were met.

In 2018, an effectiveness review was performed following the guidelines provided in NEI 14-12, Aging Management Program Effectiveness. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (Element 4), corrective action (Element 7), and operating experience (Element 10). The effectiveness review found that this program continues to be effectively implemented. Aside from two minor administrative enhancements, the PBN Environmental Qualification of Electric Equipment program was judged to be effective.

A search of the action request (AR) database in the corrective action program (CAP) for EQ related issues discovered the following:

In 2019, a pre-design basis assurance inspection (DBAI) review of the PBN Environmental Qualification of Electric Equipment program was conducted in preparation for the NRC EQ DBAI. The following findings were identified:

- The EQ master list and NAMS data fields were inconsistent
- Certain EQ maintenance requirements needed updating
- Certain EQ documentation packages needed to incorporate industry OE/NRC identified issues and provide additional bases for activation energies (eVs).

There is one remaining AR to develop an action plan to resolve remaining identified gaps and enhancements. This demonstrates the EQ program is continually self-improving.

In December 2019, PBN received notice from Ultra Electronics that the qualified life of their N-E10 series pressure transmitters had changed. This item has been placed into the corrective action program for resolution.

This demonstrates the EQ program is informed and enhanced due to the review of external plant OE.

In October 2019, the fleet EQ program coordinator requested a review of storage level requirements for EQ Rosemount transmitters based on a non-conformance violation (NCV) from Waterford. PBN subsequently determined that the EQ transmitters at PBN were properly stored in a manner for maintaining their qualified shelf life consistent with the vendor-specified temperature storage requirements.

This demonstrates the EQ program is informed and enhanced due to the review of external plant OE.

The operating experience summarized above demonstrates that the PBN Environmental Qualification of Electric Equipment AMP has proven to be effective in managing aging effects since it incorporates proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls. The continued application of these proven methods provides reasonable assurance that the effects of aging will be managed such that EQ components will continue to perform their intended functions consistent with the CLB through the SPEO. The above operating experience demonstrates that the PBN Environmental Qualification of Electric Equipment AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE. This practice will continue throughout the SPEO. In addition, AMP effectiveness is assessed at least every five years per NEI 14-12. The last effectiveness review was performed in 2018 and deemed this AMP to be effective. No gaps were identified.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Environmental Qualification of Electric Equipment AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Environmental Qualification of Electric Equipment AMP, with an enhancement, will provide reasonable assurance that the effects of aging will be managed so that the intended functions of EQ components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3 NUREG-2191 Chapter XI Aging Management Programs

This section provides summaries of the NUREG-2191 Chapter XI AMPs credited for managing the effects of aging at PBN.

B.2.3.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Program Description

The PBN ASME Section XI Inservice Inspection (ISI), Subsections IWB, IWC, and IWD AMP is an existing program where inspections identify and correct degradation in ASME Code Class 1, 2, and 3 components and piping. In accordance with 10 CFR 50.55a, ISI program plans documenting the examination and testing of Class 1, 2 and 3 components are prepared in accordance with the rules and requirements of ASME Code Section XI, 2007 Edition and Addenda through 2008. This AMP describes the long-term inspection program for Class 1, 2 and 3 components.

The AMP manages the aging effects of loss of material, cracking, and loss of mechanical closure integrity, and provides inspection and examination of accessible components, including welds, pump casings, valve bodies, and pressure-retaining bolting. This condition monitoring program includes periodic visual, surface, and volumetric examination, leakage testing of Class 1, 2, and 3 pressure-retaining components, including welds, integral attachments; pressure-retaining bolting for assessment, identification of signs of age-related degradation; and establishment of corrective actions. The program includes examinations and tests performed to identify and manage cracking, loss of fracture toughness, and loss of material in Class 1, 2, and 3 piping and components. Inspection of these components is in accordance with Subsections IWB, IWC, and IWD, respectively.

The PBN ASME Section XI, Subsections IWB, IWC, and IWD, ISI AMP inspections identify and correct degradation in Class 1, 2, and 3 components and piping. Inspection methods and frequency are determined in accordance with the requirements of Tables IWB-2500-1 (Class 1), IWC-2500-1 (Class 2), and IWD-2500-1 (Class 3). Examinations are scheduled in accordance with Inspection Program, as described by Sub-article IWB-2411 and Table IWB-2411-1 as well as the 5th Interval ISI Program (ISI Program document).

The ISI of Class 1, 2, and 3 components and integral attachments (i.e., the scope of this AMP) has been in place since initial operation of the plant, and the inspections are conducted as part of the PBN ISI AMP, currently based on the PBN ISI Program document. Examinations are performed as specified to identify the overall condition of components and to ensure that any degraded conditions identified are corrected prior to returning the component to service. The PBN ISI Program document is updated at the end of the 120-month interval to the latest approved edition of the ASME Code Section XI, identified by 10 CFR 50.55a, eighteen months prior to the end of the 120-month interval. All examinations and inspections performed in accordance with the program plan are documented by records and reports, which are submitted to the NRC as required by IWA-6000.

Inspection results are evaluated by qualified individuals in accordance with ASME Code Section XI acceptance criteria. Components with indications that do not exceed the acceptance criteria are considered acceptable for continued service. Indications that exceed the acceptance criteria are documented and evaluated in accordance with the PBN Corrective Action Program. Components will be accepted based on engineering evaluation, repair, replacement or analytical evaluation. Repairs or replacements are performed in accordance with ASME Code Section XI, Subsection IWA-4000 and IWA-6000.

In-service inspections of the PBN Units 1 and 2 ASME Code, Section XI, Appendix L pressurizer spray nozzle safe end piping will be performed once in each 10-year ISI interval with the first inspection being performed no earlier than 10 years prior to the SPEO and no later than the last refueling outage prior to the SPEO.

NUREG-2191 Consistency

The PBN ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP, with enhancement, will be consistent with the 10 elements of NUREG-2191, Section XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD.”

Exceptions to NUREG-2191

None.

Enhancements

Element Affected	**Enhancement**
4. Detection of Aging Effects	Perform In-service inspections of the PBN Units 1 and 2 ASME Code, Section XI, Appendix L pressurizer spray nozzle safe end piping at least once in each 10-year ISI interval with the first inspection being performed no earlier than 10 years prior to the SPEO and no later than the last refueling outage prior to the SPEO.

Operating Experience

Industry Operating Experience

PBN evaluates industry OE items for applicability per the NextEra Fleet OE Program and takes corrective actions, when necessary.

- Information Notice (IN) 2001-05, Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3. This IN discusses the detection of through-wall circumferential cracks in two of the control rod drive mechanism (CRDM) penetration nozzles and weldments at the Oconee Nuclear Station, Unit 3 (ONS3). After reviewing industry literature, attending industry workshops and owners group meetings, it was determined that PBN is susceptible to similar cracking in the CRDM mechanisms. A model was developed by the EPRI materials reliability program (MRP) that ranked the industry plants relative to Oconee 3. PBN Unit 2 was ranked 8.8 EFPY away from ONS3 whereas Unit 1 was 10.9 EFPY away from ONS3. Subsequent regulatory requirements were identified by the NRC in Bulletin 2001-01. Site approach was coordinated through the industry and Nuclear Management Company (NMC). PBN committed to perform VT-2 inspection of the RPV head and nozzles for leakage, which was performed in 2002 with no indications identified.

- IN 2003-11 Supplement 1, Leakage Found on Bottom-mounted Instrumentation Nozzles. This notice discusses the issue of indications of leakage in the form of boron deposits discovered on bottom-mounted instrumentation (BMI) nozzles at South Texas Project Unit 1 (STP Unit 1). This issue was completely reviewed and actions taken following release of MRP notification letters in April 2003 and following the NRC issues of NRC Bulletin 2003-02. PBN responded to the bulletin on September 22, 2003 in NMC Letter NRC 2003-0089 (Reference ML032671205). In that letter PBN committed to performance of the recommended visual examinations of the BMI penetrations as requested. No indications were identified.

- IN 2004-11, Cracking in Pressurizer Safety and Relief Nozzles and in Surge Line Nozzle. NRC IN 2004-11 states that indications were found in Alloy 82/182 weld metal on pressurizer nozzles, but the indications did not extend into the base metal. This issue is not applicable to PBN because there are no Alloy 600 or Inconel 82/182 welds in the Pressurizers. However, the PBN Boric Acid Corrosion and ISI AMPs have been strengthened over the last few years to monitor for these types of indications.

- Westinghouse TB-04-19, NRC IN 05-02: Pressure Boundary Leakage at Steam Generator Bowl Drain Welds. These original industry OE documents prompted PBN to do bare metal exams of these welds on both Unit 1 steam generators every refueling outage as part of the ISI AMP. Unit 2 does not have this configuration. As industry events continued to occur, these connections were modified to remove the susceptible material eliminating the need for the bare metal exams.

- IN 2006-27, Circumferential Cracking in the Stainless Steel Pressurizer Heater Sleeves of Pressurized Water Reactors. This issue was evaluated for PBN and as a result no further action was required.

- IN 14-02, Failure to Properly Pressure Test Reactor Vessel Flange Leak-Off Lines. This IN was evaluated for PBN and resulted in moving the Class 1 boundary to the RV flange, thus eliminating the need to pressure test the leak-off lines.

The examples above demonstrate that the PBN ISI AMP reviews and incorporates applicable industry OE into the program so that the ISI AMP will continue to be effective during the SPEO.

Plant Specific Operating Experience

Owner's Activity Reports (OARs) were reviewed over the last five years (2014-2019). There were no flaws identified nor any other significant issues reported during this time period.

Integrated Inspection reports over the last five years (2014-2019) identified 3 (total) non-cited violations (NCVs) regarding either procedure compliance or inspection techniques in 2014 and 2015. No findings were identified in 2016-2019. No findings were related to flaws or flaw growth.

Several post-approval NRC reviews have been performed since 2010. The NRC reviews the licensing basis, program basis document, implementing procedures, assessments, and related CRs; and interviewed the plant personnel responsible for the AMPs. The NRC also reviewed the self-assessment reports completed in 2006 and 2010, and the corrective actions resulting from the assessment. The NRC verified that program implementing documents contain the appropriate License Renewal references. The inspectors verified that the program and enhancements were in place involving revisions to existing activities credited for license renewal, to ensure that inspections for the applicable aging effects are performed and any noted indications are appropriately evaluated.

In 2018, an effectiveness review of the ISI AMP was performed following the guidelines provided in NEI 14-12, Aging Management Program Effectiveness. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (Element 4), corrective action (Element 7), and operating experience (Element 10). The effectiveness review found that ISI AMP continues to be effectively implemented.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN ISI AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.2 Water Chemistry

Program Description

The PBN Water Chemistry AMP, previously known as the Water Chemistry Control Program, is an existing AMP that manages loss of material due to corrosion and cracking due to SCC and related mechanisms, and reduction of heat transfer due to fouling in components exposed to a treated water environment. This AMP includes periodic monitoring of the treated water in order to minimize loss of material or cracking. The PBN Water Chemistry AMP relies on monitoring and control of reactor water chemistry based on industry guidelines contained in Electric Power Research Institute (EPRI) 3002000505 (Reference 1.6.50), "PWR Primary Water Chemistry Guidelines," and EPRI 3002010645 (Reference 1.6.51), "PWR Secondary Water Chemistry Guidelines."

The PBN Water Chemistry AMP is generally effective in removing impurities from intermediate and high-flow areas; however, NUREG-2191 also identifies those circumstances in which this AMP is to be augmented to manage the effects of aging for SLR. For example, the PBN Water Chemistry AMP may not be effective in low-flow or stagnant-flow areas. Accordingly, in certain cases as identified in NUREG-2191, verification of the effectiveness of this AMP is undertaken to provide reasonable assurance that significant degradation is not occurring and the component intended function is maintained during the SPEO. For these specific cases, the PBN One-Time Inspection AMP (Section B.2.3.20) is used to perform inspections of selected components at susceptible locations in the system to be completed prior to the SPEO. This AMP addresses the metallic components subject to AMR that are exposed to a treated water environment.

This PBN Water Chemistry AMP includes specifications for chemical species, impurities and additives, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry. System water chemistry is controlled to minimize contaminant concentration and mitigate loss of material due to general, crevice, and pitting corrosion and cracking caused by SCC. Additives are used for reactivity control and to control pH and inhibit corrosion.

This AMP monitors concentrations of corrosive impurities and water quality in accordance with the EPRI water chemistry guidelines to mitigate loss of material, cracking, and reduction of heat transfer. Chemical species and water quality are monitored by in-process methods and through sampling, and the chemical integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples. Chemistry parameter data are recorded, evaluated, and trended in accordance with the EPRI primary and secondary water chemistry guidelines, and maximum levels for various chemical parameters are maintained within the system-specific limits that are consistent with the EPRI primary and secondary water chemistry guidelines.

Any evidence of aging effects or unacceptable water chemistry results are evaluated, the cause identified, and the condition corrected. When measured water chemistry parameters are outside the specified range, corrective actions are taken to bring the parameter back within the acceptable range (or to change the operational mode of the plant) within the time period in the Primary Water Chemistry Monitoring Program and the Secondary Water Chemistry Monitoring Program. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling or other appropriate actions are taken and analyzed to verify that the corrective actions were effective in returning the concentrations of contaminants, such as chlorides, fluorides, sulfates, and dissolved oxygen, to within the acceptable ranges.

NUREG-2191 Consistency

The PBN Water Chemistry AMP will be consistent, with exception, with the 10 elements of NUREG-2191, Section XI.M2, “Water Chemistry” as modified by SLR-ISG-Mechanical-2020-XX, Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance.

Exceptions to NUREG-2191

The NUREG-2191 Chapter XI.M2, Water Chemistry aging management program monitors parameters of various plant water systems in accordance with the guidelines contained in EPRI 1014986, “PWR Primary Water Chemistry Guidelines,” Revision 7 and EPRI 1016555, “PWR Secondary Water Chemistry Guidelines,” Revision 8. The scope of the PBN Water Chemistry aging management program includes treated water within the Heating Steam System which does not fall under the scope of EPRI 1014986 and EPRI 1016555.

There is currently no NUREG-2191 program that addresses water chemistry for treated water within the Heating Steam System. The PBN Water Chemistry program as an enhancement will include chemistry controls for the Heating Steam System. The critical chemistry parameters for the Heating Steam System will be monitored in accordance with industry standards, specifically ASME standard ISBN-0-7918-1204-9, “Consensus on Operating Practices for the Control of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers.” A review of industry operating experience indicates that the chemistry controls for this environment are adequate to mitigate aging. The effectiveness of this portion of the Water Chemistry program will be verified by a one-time inspection of selected Heating Steam System components as part of the One-Time Inspection (B.2.3.20) program.

Enhancements

The PBN Water Chemistry AMP will be enhanced as follows for alignment with NUREG-2191. Enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	• Incorporate monitoring the critical chemistry parameters for the Heating Steam System in accordance with industry standards, specifically ASME standard ISBN-0-7918-1204-9, “Consensus on Operating Practices for the Control of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers.” • Perform a one-time inspection to verify the effectiveness of monitoring the critical chemistry parameters for the Heating Steam Systems in accordance with industry standards, specifically ASME stands ISBN-0-7918-1204-9, “Consensus on Operating Practices for the Control of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers.”

Operating Experience

The PBN Water Chemistry AMP has been effective at maintaining desired system water chemistry and detecting abnormal conditions which are corrected in an expedient manner. A review of OE supports the above statement as most are related to abnormal chemistry results during operational transients such as startups. Although the abnormal conditions are expected during these transients, the corrective action program is used for documentation.

The EPRI guidelines for water chemistry are being used and the controlling procedures refer and adhere to the limits specified in them. Over time, this has proven to be an effective method of controlling concentrations of parameters such as sulfates, chlorides, fluorides, dissolved oxygen, lithium, sodium, iron, and copper that are detrimental to certain alloys in both the primary and secondary systems. Controlling these parameters mitigates aging effects in primary and secondary system components.

Review of plant-specific operating experience also indicates that the chemistry program is performing its function of mitigating aging effects. No reports were found that attributed water chemistry as the cause of component deterioration, aging effects, and/or failing to perform its function. Action Requests are initiated when water chemistry is found to be out of specification, and most of the instances occur during start-up when parameters are quickly changing, and water chemistry is more difficult to control. The time durations of out of specification water chemistry are minimal and there is no evidence of having caused detrimental effects on system components

<u>Industry Operating Experience</u>

- The secondary water chemistry control program is periodically updated to address new technologies and industry experience. The PBN Secondary Strategic Water Chemistry Optimization Plan is reviewed every 2 years to ensure it continues to reflect PBN secondary water chemistry philosophies and goals implemented via the PBN Secondary Water Chemistry Monitoring Program.

- Industry experience has shown that maintaining feed water hydrazine concentrations of at least 8 times the feed source dissolved oxygen concentration is needed to achieve low Electrochemical Potential (ECP) values in the steam generators. Oxygen concentration is primarily measured at the final feed water sample point. Low ECP values are indicative of a non-corrosive, reducing environment. PBN feed water hydrazine concentration is administratively kept at a minimum of 8 times the dissolved oxygen concentration of the system or 20 ppb, whichever is higher. The normal feed water hydrazine concentration is controlled at approximately 40-60 ppb.

- Carbo-hydrazide is added as a metal passivator and an oxygen scavenger. Experimental and industry data has shown that carbo-hydrazide is a better metal passivator than hydrazine at wet lay-up bulk water temperatures. Specifically, the formation of a protective layer of magnetite occurs faster with carbo-hydrazide than hydrazine. Carbo-hydrazide is added to the steam generator bulk water at a concentration of approximately 25 to 75 ppm. Carbo-hydrazide has been analyzed for use during wet lay-up and start up.

Plant Specific Operating Experience

- The effectiveness of the PBN Water Chemistry AMP was demonstrated as a result of the October 2010 and March 2013 NRC Phase 2 post-approval site inspections which were conducted on Units 1 and 2, respectively, prior to entering into the original PEO for each unit. The inspectors reviewed the licensing basis, program basis document, implementing procedures, and completed inspections; and interviewed the PBN plant personnel responsible for this program. The inspectors verified that program and associated enhancements were in place. Based on review of the timeliness and adequacy of PBN's actions, the inspectors determined PBN had met the required commitments for the PBN Water Chemistry AMP.

- During the Unit 1 refueling outage in 2014, PBN encountered higher than expected dose rates. This was documented in a root cause evaluation. The PBN Water Chemistry AMP was revised to incorporate program review recommendations to improve shutdown chemistry strategies and reduce reactor coolant system crud source terms. These changes focused on preventing unanticipated RCS crud releases to minimize dose in future refueling outages. Specific changes included refinements to RCS hydrogen peroxide and hydrazine additions, improved RCS iron and nickel measurements, implementation of a sub-micron RCS filter strategy, implementation of spent fuel pool and cavity sub-micron filters, specific outage schedule logic updates to better control hydrogen reductions, and source term reductions.

  Part of the long-term corrective actions was to perform analysis studies and fuel vendor evaluations to increase the pH regime to address the higher boiling duties of the PBN cores due to implementation of the extended power updates in 2011. The increase called for reaching the at temperature pH of 7.2 earlier in the fuel cycle to a pH of 7.4 at the end of the fuel cycle.

- In 2016, a Nuclear Oversight (NOS) Finding was issued relating to PBN Water Chemistry AMP oversight, roles and responsibilities. The Finding was subsequently closed by NOS with implementation of corrective actions made to address AMP oversight, roles and responsibilities.

- In 2017, PBN adopted the use of Poly Acrylic Acid (PAA) in wet layup conditions as part of a reduction in corrosion product transport strategy to both units' secondary systems. These are not industry requirements, but strategies used in the industry to enhance iron removal during wet layup conditions and reduce overall corrosion product transport to the steam generators. PBN now adds PAA to the steam generators and condensate systems for wet layup conditions as a program improvement.

- In 2018, Unit 2 RCS chlorides were above the administrative level. The source of the chlorides was the lithium hydroxide demineralizer which was not equilibrated when the level was observed. The chlorides concentrations peaked at well below Action Levels and slowly trended down within the administrative level once reactor power reached 90 percent.

- In 2018, an effectiveness review of the PBN Water Chemistry AMP was performed following the guidelines provided in NEI 14-12, Aging Management Program Effectiveness. The effectiveness review covered the applicable ten program elements with focuses on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). In response to the AMP effectiveness review, the PBN Water Chemistry AMP basis document was updated to include the new revision of EPRI guidelines. The PBN Water Chemistry AMP was determined to continue to be effectively implemented, and there were no gaps identified for the program.

- In 2019, sulfate level and radioactivity in the spent fuel pool were higher than normal for a couple of weeks during the new fuel receipt and fuel moves in the pool. The spent fuel pool system mixed bed demineralizer outlet was < 1 ppb for sulfate and resin was still removing sulfate and radioactivity with 99 percent efficiency. The mixed bed demineralizer resin was replaced.

- In 2019, during a Unit 2 chemical volume and control system cation demineralizer flush, more than expected water was blended to the RCS resulting in the RCS lithium concentration falling below the lower control limit and causing an Action Level 1 condition to be reached. The cause was attributed to a knowledge gap and imprecise communication. To enhance margin for RCS lithium control, a control and surveillance of demineralizer resin procedure was created to add flushing and sampling acceptance criteria, and steps for operations to obtain the desired flush volume from the chemistry department. Additionally, a technical procedure to verify, predict and control lithium was updated to require chemistry manager approval for any control actions that may cause lithium administrative limits to be exceeded.

- In 2019, the NRC performed the 71003 Phase 4 inspections at PBN Units 1 and 2. The team selected seven AMPs for evaluation considering risk insights and programs that were enhanced or new under the renewed operating license. The PBN Water Chemistry AMP was not one of the AMPs selected for this inspection.

- The PBN Water Chemistry health reports from January 2015 through February 2020 were evaluated as part of the SLRA OE review. From the first quarter of 2015 through the first quarter of 2019, the program health was “green.” From the second quarter of 2019 to the fourth quarter of 2019, the program health was “white” due mainly to the conservative scoring method (e.g. a score of zero is given for outage performance until all corrective actions are completed or until the next data is available). As of the first quarter of 2020, the program health is “green.”

The OE relative to the PBN Water Chemistry AMP provides objective evidence that the existing program will continue to effectively detect and trend aging effects. A review of the operating experience examples shows that inspections have been effective in discovering abnormal conditions and responding to the conditions with corrective actions prior to resulting adverse water chemistry conditions and/or loss of component intended function.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Water Chemistry AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Water Chemistry AMP, with exception, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.3 Reactor Head Closure Stud Bolting

Program Description

The PBN Reactor Head Closure Stud Bolting AMP is an existing AMP for SLR, related to and currently part of the ASME Section XI, Subsections IWB, IWC and IWD (Section B.2.3.1), portion of the PBN ISI Program. This AMP provides (a) inservice inspection (ISI) in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB, Table IWB 2500-1; and (b) preventive measures to mitigate cracking. This AMP is in accordance with the regulatory position delineated in NRC RG 1.65 Revision 1 (Reference 1.6.52), "Materials and Inspections for Reactor Vessel Closure Studs." The scope of this AMP includes:

- Closure head nuts
- Closure studs
- Threads in the RPV flange
- Closure washers and bushings

Through inspections performed as part of the PBN ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1), the reactor head closure stud bolting is managed for aging effects due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC), and loss of material due to corrosion or wear. In accordance with the 2007 edition of the ASME Code Section XI, with 2008 addenda, the Subsection IWB categorization and methods for ISI are listed in Table B-5 below:

Table B-5
ASME Code Section XI, Subsection IWB Inspection Methods

Examination Category	Item Number	Description of Component Examined	Examination Method(s)
B-G-1 Pressure Retaining Bolting, Greater than 2 in. in Diameter	B6.10	Closure Head Nuts	VT-1 Visual
	B6.20	Closure Studs	Volumetric or Surface
	B6.40	Threads in Flange	Volumetric
	B6.50	Closure Washers, Bushings	VT-1 Visual

This AMP monitors material conditions and imperfections and detects loss of material by performing visual inspections (VT-1), surface examinations (liquid penetrant and magnetic particle), and volumetric examinations in accordance with the requirements specified in Table IWB-2500-1. The specific type of inspection to be performed for each of the different bolting components is listed in the PBN ISI Program Plan. Components are examined for evidence of operation-induced flaws (cracking, pitting) using volumetric and surface techniques. The VT-1 visual inspection is used to detect cracks, symptoms of wear, corrosion, or physical damage. The extent and frequency of inspections is specified in Table IWB-2500-1, as modified in accordance with the PBN ISI Program Plan.

Appropriate preventive measures have been used for the reactor head closure stud bolting based on site OE and best practices. PBN took one exception to preventive measure (Element 2 (d)).

This AMP ensures that the frequency and scope of examination of the reactor head closure stud bolting is sufficient so that the aging effects are detected before the component(s) intended function(s) would be compromised or lost. Inspections are performed in accordance with the inspection intervals specified by IWB-2400, as reflected in the PBN ISI Program Plan. These examinations are scheduled in accordance with the PBN ISI Program Plan and will be continued during the SPEO.

The acceptance criteria associated with this AMP, provided in the PBN ISI Program Plan, are based on the acceptance standards for the inspections identified in Subsection IWB for the reactor head closure stud bolting. Table IWB-2500-1 identifies references to acceptance standards listed in IWB-3500. When areas of degradation are identified, an engineering evaluation is performed to determine if the component is acceptable for continued service, or if repair or replacement is required in accordance with Subsections IWB, IWA-4000, and IWA-6000. The engineering evaluation includes probable cause, the extent of degradation, the nature and frequency of additional examinations, and whether repair or replacement is required. In addition, the material inspection and maximum yield strength information provided in the regulatory position of NRC RG 1.65 Revision 1 will be included in the program, for completeness, prior to entering the SPEO.

NUREG-2191 Consistency

The PBN Reactor Head Closure Stud Bolting AMP will be consistent, with exception and enhancements, with the 10 elements of NUREG-2191, Section XI.M3, “Reactor Head Closure Stud Bolting.”

Exceptions to NUREG-2191

NUREG-2191 recommends, as a preventive measure that can reduce the potential for SSC or IGSCC, using bolting material for the reactor head closure studs that have an ultimate tensile strength limited to less than 1,172 megapascals (MPa) (170 kilo-pounds per square inch (ksi)) for existing bolting material (NUREG-1339). PBN closure stud bolting is considered high strength steel (SLRA Section 3.1.1), and PBN is taking exception to Element 2(d), Preventive Actions. The exception is acceptable because PBN meets all other program element requirements for reactor head closure stud bolting and will enhance the program so that replacement bolts are limited to a yield strength of 150 ksi.

Enhancements

The PBN Reactor Head Closure Stud Bolting AMP will be enhanced for alignment with NUREG-2191, as discussed below. The changes and enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Revise the procurement requirements for reactor head closure stud material to ensure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi.
7. Corrective Actions	Revise the procurement requirements for reactor head closure stud material to ensure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi.

Operating Experience

Industry Operating Experience

PBN evaluates industry OE items for applicability per the NextEra Fleet OE Program and takes corrective actions, when necessary. Industry OE includes:

Turkey Point Nuclear Generating Station:

- In April 2016, a reactor vessel head stud was found not to meet the elongation criteria after tensioning was complete, and as a result a corrective action program (CAP) item was created. The stud exceeded the Level I elongation acceptance criterion, which considers only the elongation of the subject stud, by 1 mil. The procedure allows a Level II elongation criterion, which considers the average elongation of the subject stud and the adjacent studs. The stud was determined to meet the Level II elongation criterion and was thus acceptable for continued use, and the CAP item was closed.

- During the Unit 3 Spring of 2012 refueling outage, performance of the ASME Section XI Inservice Inspection of reactor head bolting led to the discovery of corrosion on the lower threads of three reactor head closure nuts. One of the nuts also had nicks in the top two threads. Visual inspection was performed on the mating studs, and no issues were identified. An evaluation was performed to determine possible causes of the corrosion and determine a method for mitigating future damage. The evaluation included inspection of all 58 reactor head closure nuts. No visual evidence of boric acid leakage was documented in the evaluation. Additionally, no industry OE identified the lubricant in use as corrosion-causing. The evaluation concluded that the corrosion was superficial and could be easily removed. Small gouges and scratches exposing the raw material were also seen with no corrosion. The most likely cause of the corrosion was determined to be another material deposited on the threads during installation. A like-for-like replacement of the three nuts was performed during the outage.

Surry Power Station:

- In May 2012, while in the process of cleaning and inspecting the Unit 1 reactor vessel closure studs, one stud (#21) was found to have some minor thread wear on the first seven threads at the bottom of the stud. Engineering was contacted and found the threads were rounded on the outer edges of the male threads. Engineering concluded that the condition did not impact the ability of the stud to carry its load nor impact the ability to thread the stud in or out of the reactor vessel flange. For those reasons, the reactor vessel flange threads were evaluated to be satisfactory and returned to service.

- In November 2013, while removing the plugs from the Unit 1 reactor vessel flange holes, 55 of 58 stud holes were found to be flooded with cavity water which could lead to boric acid corrosion. The remaining three holes used a different sealing mechanism design. The plug design for the 55 holes was determined to be ineffective. The stud holes were cleaned and inspected in accordance with maintenance procedures, and reassembly of the reactor vessel continued. After the outage, new plugs were fabricated to replace the failed ones, using a design similar to the effective plugs used at North Anna Power Station. No subsequent operating experience has been found to indicate an ongoing concern with flooding in the stud holes.

- In November 2015, during an ASME Code, Section XI ultrasonic (UT) examination of one Unit 2 reactor vessel closure stud (# 34), the normal and expected UT signal patterns for an acceptable stud could not be obtained. The UT examination of reactor vessel closure stud was not accepted, per ASME Code, Section XI, Category B-G-1. The decision was made to replace the Unit 2 stud, which was completed during that refueling outage.

The examples above demonstrate that the PBN Reactor Head Closure Stud Bolting AMP reviews OE and incorporates applicable industry OE into the program so that the program will continue to be effective during the SPEO.

Plant Specific Operating Experience

A search of Condition Reports and Maintenance Work Orders on reactor head closure studs for both PBN Units 1 and 2 revealed that no degradation of the studs or nuts has been detected. A review of Action Reports at PBN did not result in any Reactor Head Closure Stud Bolting issues or degradation.

To assess effectiveness of AMPs credited for subsequent license renewal, the AMPs are reviewed against the criteria provided in NEI 14-12. The most recent effectiveness review of Aging Management Programs at PBN was performed in 2018. The effectiveness review covered the applicable ten program elements with particular attention on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). There were no gaps identified related to Reactor Head Closure Stud Bolting during the review of the Inservice Inspection program and the program was deemed effective. AMP effectiveness reviews are performed at least every five years.

The PBN Reactor Head Closure Stud Bolting AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Reactor Head Closure Stud Bolting AMP, with exception and enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.4 Boric Acid Corrosion

Program Description

The PBN Boric Acid Corrosion AMP is an existing AMP that manages the aging effects of loss of material, increased resistance of connection, and mechanical closure integrity due to aggressive chemical attack resulting from borated water leaks. This AMP relies, in part, on the response to NRC Generic Letter (GL) 88-05 (Reference ML053070378), as documented in FPL letter L-88-239 (Reference ML17345A225), to identify, evaluate, and correct borated water leaks that could cause corrosion damage to reactor coolant pressure boundary components. The AMP also includes inspections, evaluations, and corrective actions for all components, including electrical, subject to AMR that may be adversely affected by some form of borated water leakage. The effects of boric acid corrosion on reactor coolant pressure boundary materials in the vicinity of nickel-alloy components are also addressed by the PBN AMP that is associated with NUREG-2191, Section XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs Only)."

In addition, the PBN Boric Acid Corrosion AMP includes provisions to initiate evaluations and assessments when leakage is discovered by other plant activities not associated with this AMP. This AMP follows the guidance described in Section 7 of WCAP-15988-NP (Reference ML041190170), "Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors."

The PBN Boric Acid Corrosion AMP covers any susceptible SSC (systems, structures, and components) on which boric acid corrosion may occur and electrical components onto which borated reactor water may leak. This AMP includes provisions in response to the recommendations of NRC GL 88-05. This AMP provides the following:

- Determination of the principal location of leakage;
- Examinations and procedures for locating small leaks, and;
- Engineering evaluations and corrective actions to provide reasonable assurance that boric acid corrosion does not lead to degradation of the leakage source or adjacent SCCs.

This AMP is credited with managing boric acid corrosion for SSCs located adjacent to or in the vicinity of borated water systems and susceptible to leakage (or spray). The PBN Boric Acid Corrosion AMP minimizes exposure of susceptible materials to borated water by frequent monitoring of the locations where potential leakage could occur and timely cleaning and repair if leakage is detected. The removal of concentrated boric acid, boric acid residue, and elimination of borated water leakage mitigates corrosion by minimizing the exposure of the susceptible material to the corrosive environment.

Borated water leakage and areas of resulting boric acid corrosion are evaluated and corrected in accordance with the applicable provisions of NRC GL 88-05 and the

Point Beach Corrective Action Process. Any detected boric acid crystal buildup or deposits are cleaned. Per the NRC GL 88-05 recommendation, an objective of the PBN Boric Acid Corrosion AMP is to ensure that corrective actions are taken to prevent recurrences of degradation caused by borated water leakage.

Leakage identification is primarily by visual personnel observations and scheduled inspections and surveillances; however, this identification is supplemented, as appropriate, using methods such as RCS water inventory balancing and using Reactor Building Radiation Monitors capable of detecting RCS pressure boundary leakage. The monitors are extremely sensitive to leakage from the RCS pressure boundary, due to the sealed nature of the PBN Containment Buildings. The RCS leak rate associated with the RCS inventory balancing is calculated every shift as required by technical specifications. These leak rate calculations can help identify new leaks. Additionally, the PBN Boric Acid Corrosion AMP includes appropriate interfaces with other site programs, such as Chemistry, Operations, Work Control, and Engineering.

The procedures associated with this AMP will also be annotated no later than six months prior to entering the SPEO, as discussed below.

NUREG-2191 Consistency

The PBN Boric Acid Corrosion AMP, with enhancement, will be consistent with the 10 elements of NUREG-2191, Section XI.M10, "Boric Acid Corrosion."

Exceptions to NUREG-2191

None.

Enhancements

The PBN Boric Acid Corrosion AMP will be enhanced as follows for alignment with NUREG-2191. Enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	**Enhancement**
3. Parameters Monitored or Inspected	Coordinate with the PBN Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components AMP regarding evidence of boric acid residue (plating out of moist steam) <u>inside</u> containment cooler housings or similar locations such as cooling unit drain pans.

Operating Experience

<u>Industry Operating Experience</u>

PBN evaluates industry OE items for applicability per the NextEra Fleet OE Program and takes corrective actions or refines programs and procedures, when necessary. For example:

- PBN response to NRC Bulletin 2002-001, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity, Letter No. NRC 2002-0043” (Reference ML020770497), included a description and evaluation of PBN's inspection program that concluded the PBN Boric Acid Corrosion AMP was in compliance with the guidance of GL 88-05.

- NRC Notice 2003-02 (Reference ML030160004) was issued as a result of identified cracking and leakage of two RPV lower head penetrations at South Texas Project Unit 1. PBN provided detailed information pertaining to its RPV lower head penetration inspection program in Letter NRC 2005-0008, completed the inspections through the ASME Section XI, Subsections IWB, IWC, and IWD AMP and refined the PBN Boric Acid Corrosion AMP documents as appropriate.

- A 2015 INPO Event Report (IER) 15-9 addressing a compression-fitting leak on an RCS sample line at Sequoyah that resulted in entry into an abnormal operating procedure (AOP), the spread of contamination, and evacuation of the Auxiliary Building was evaluated by PBN regarding the applicability of the IER lesson(s) learned. In response, PBN updated the procedure to identify timely cleaning and reviewed training requirements for installing, disassembly, and reassembly of compressed fittings.

- Boric acid can also become airborne, such as moist steam inside cooling units or on cooling coils and other ventilation or filtration components, and cause corrosion in locations other than the vicinity of the leak as described in Licensee Event Reports (LER) 2010-006 for Turkey Point and LER 2002-008 for Davis-Besse. While no boric acid wastage has been identified on PBN cooling units/coils, the PBN BAC AMP is enhanced as described above regarding coordination with the AMP providing opportunistic inspection inside such components.

Plant Specific Operating Experience

The PBN Boric Acid Corrosion AMP is a mature, established program. Its effectiveness has been demonstrated as a result of the October 2010 and March 2013 NRC Phase 2 post-approval site inspections (Inspection Reports 05000266/2010-011 and 05000301/2013008) which were conducted prior to entering into the PEO for each unit. The inspectors reviewed the licensing basis, program basis document, implementing procedures, and completed inspections; and interviewed the PBN plant personnel responsible for this program. The inspectors verified that program and associated enhancements were in place. Based on review of the timeliness and adequacy of PBN’s actions, the inspectors determined PBN had met the required commitments for the PBN Boric Acid Corrosion AMP.

An effectiveness review of the PBN Boric Acid Corrosion AMP was performed in 2018 following the guidelines provided in NEI 14-12, Aging Management Program Effectiveness. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (Element 4), corrective action (Element 7), and operating experience (Element 10). The review found the PBN Boric Acid Corrosion AMP to remain effective.

A large percentage of the work orders and condition reports/action requests initiated for identified leaks described finding dried boric acid crystal deposits either on the component from which it leaked or on the floor below the leaking component. Occasionally, dried boric acid crystals were found on components located below the leaking component. Many of the work orders initiated to repair and/or investigate evidence of borated water leakage were a result of performing system walkdowns.

A recent instance of boric acid accumulation and degradation of a Unit 2 Hot Leg Sample valve occurred in 2014 and 2017. The valve was cleaned, and an evaluation performed that projected the valve yoke would require future replacement. The valve yoke was replaced during the Fall 2018 and the Spring 2020 refueling outage with full valve replacement schedule for the Fall 2021 refueling outage.

An inconsistency between the forms in the PBN and fleet procedures was identified in February 2019. The inconsistencies in forms were reviewed and appropriate updates made to more closely align the site AMP with the fleet procedure.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Boric Acid Corrosion AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Boric Acid Corrosion AMP, with enhancement, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.5 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

Program Description

The PBN Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP is an existing AMP, previously the PBN Reactor Coolant System Alloy 600 Inspection Program, which manages the aging effect of primary water stress corrosion cracking (PWSCC) for pertinent materials (Alloy 600/82/182) in the reactor coolant pressure boundary. The PBN Unit 1 and 2 reactor vessel heads (RVHs) were replaced in 2005 due to the susceptibility of the Alloy 600 penetrations to PWSCC. The replacement RVHs utilize more PWSCC resistant, Alloy- 690 materials on all head penetrations. Visual examination of the Unit 1 and 2 RVH external surfaces during outages and through the PBN Boric Acid Corrosion AMP are utilized to manage cracking. Future inspections of the RVHs are in accordance with ASME Code Case N-729, which has been included in the PBN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program that includes the conditions listed in 10 CFR 50.55a. PBN will continue to monitor industry programs to ensure that PWSCC is managed for the SPEO. This AMP is used in conjunction with the following PBN AMPs:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1).
- Boric Acid Corrosion AMP (Section B.2.3.4).
- Water Chemistry AMP (Section B.2.3.2).

The scope of this AMP includes nickel-alloy components, welds identified in ASME Code Cases N-729, N-722, and N-770 as mandated with conditions in 10 CFR 50.55a, and components susceptible to corrosion by boric acid nearby or adjacent to those nickel alloy components. This AMP manages cracking due to PWSCC and loss of material due to boric acid corrosion through the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Boric Acid Corrosion AMP, respectively.

The reactor coolant system leak rate associated with inventory balancing is calculated frequently, as required by PBN Technical Specifications, Section 3.4.13, and these leak rate calculations can help identify new leaks. Flaw evaluation through 10 CFR 50.55a is used to monitor cracking. Detected flaws are monitored and trended through periodic and successive inspections in accordance with ASME Code Cases N-729, N-722, and N-770 as mandated with conditions in 10 CFR 50.55a. The nickel-alloy components within the scope of this AMP are evaluated against the acceptance criteria contained in the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD AMP (Section B.2.3.1); boric acid residue or corrosion products are evaluated by the Boric Acid Corrosion AMP (Section B.2.3.4) to determine the leakage source and impact on adjacent and nearby susceptible components.

Components with relevant unacceptable flaw indications are corrected for further services through the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD AMP (Section B.2.3.1), which also manages their repair and replacement procedures and activities in accordance with 10 CFR 50.55a and NRC RG 1.147. Expansion of current inspections and increased inspection frequencies are conducted, as necessary, by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1) for evidence of cracking in susceptible components and by the PBN Boric Acid Corrosion AMP (Section B.2.3.4) for detection of leakage.

The Alloy 600 Management Program procedure, based on EPRI MRP-126 (Reference ML051450557), in conjunction with the 5th Interval Inservice Inspection Plan, lists current inspection requirements for nickel-alloy components at PBN.

NUREG-2191 Consistency

The PBN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP, with enhancement, will be consistent with the 10 elements of NUREG-2191, Section XI.M11B, “Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs Only).”

Exceptions to NUREG-2191

None.

Enhancements

The PBN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Update the existing license renewal controls for the plant modification process to ensure that no additional nickel alloys will be used in reactor coolant pressure boundary applications during the SPEO or that, if used, appropriate baseline and subsequent inspections per MRP inspection guidance will be put in place.

Operating Experience

Industry Operating Experience

Industry OE and information from NSSS vendors is evaluated for effect on inspection requirements. Industry OE has included:

- NRC IN 2005-02 (February 4, 2005) “Catawba SG Bowl Drain Cracking,” described the discovery of boric acid deposits in the vicinity of a Steam Generator (SG) bowl drain line while conducting bare metal visual examinations of the plants Alloy 600/82/182 components during the Fall 2004

Unit 2 refueling outage (RFO). The hot and cold leg temperatures were reported to be 617° F and 588°F, respectively. The leakage would have gone undetected if the surrounding insulation had not been removed to facilitate the inspections. At PBN, a similar steam generator channel head drain line configuration existed in the Unit 1 steam generators. An engineering change removed the Alloy 600 (Alloy 82/182) weld filler metal and heat-affected zone for the Point Beach Unit 1 Steam Generator Channel Head Bowl drains. The welds were replaced with partial-thickness Alloy 690 (Alloy 52) welds.

- NRC Regulatory Issue Summary 2008-25 (October 2, 2008) "Regulatory Approach For Primary Water Stress Corrosion Cracking Of Dissimilar Metal Butt Welds In Pressurized Water Reactor Primary Coolant System Piping" described the regulatory approach for ensuring the integrity of primary coolant system dissimilar metal (DM) butt welds containing Alloy 82/182 in pressurized-water reactor (PWR) power plants. This RIS concluded that MRP-139 and the MRP interim guidance letters, with the exception of the reinspection interval for unmitigated pressurizer DM butt welds as addressed by the Confirmatory Action Letters (CALs), provide adequate protection of public health and safety for addressing PWSCC in butt welds for the near term pending incorporation by reference into 10 CFR 50.55a of an ASME Code Case containing comprehensive inspection requirements. PBN follows MRP-139 and therefore also addresses PWSCC in butt welds applicable to this IN.

- Westinghouse communications, March 31, 2010 - Visual evidence that RV clevis insert cap screws had cracked was found at D.C. Cook during the 10-year in-service inspection (ISI). Visual (VT-3) examinations of the PBN Unit 1 and Unit 2 clevis inserts were performed during the 10-year ISI in the Unit 1 Spring 2010 and Unit 2 Fall 2009 refueling outages. No indications of wear, fracture, or other anomalies with the clevis insert cap screws or dowel pins were noted at any location.

- Westinghouse communications, August 25, 2014 – This document provides a summary of the OE as well as root cause findings and the applicability of these findings on Westinghouse and Combustion Engineering (CE) pressurized water reactor designs. This TB also reviews the safety implications of the OE and root cause analysis results as well as inspection recommendations for licensees to consider including as part of their aging management program to address this OE. The actions for PBN as a result of this OE was to include the RV clevis inserts and lock keys are included in the Alloy 600 Management Program procedure, with a Plan Summary to follow EPRI and Westinghouse recommendations on inspections

- NRC Regulatory Issue Summary 2015-10 (July 16, 2015), Applicability of ASME Code Case N-770-1 as Conditioned in 10 CFR 50.55a, "Codes and Standards," to Branch Connection Butt Welds. This RIS informs addressees about reactor coolant system (RCS) Alloy 82/182 branch connection dissimilar metal nozzle welds that may be of a butt weld configuration and therefore require inspection under 10 CFR 50.55a(g)(6)(ii)(F), "Augmented ISI [inservice inspection] requirements: Examination requirements for Class 1 piping and nozzle dissimilar-metal butt welds." This RIS required no action or written response. An Operating Experience Evaluation was completed in response to this RIS and concluded that PBN met NRC regulations regarding inspection requirements.

The examples above demonstrate that the PBN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP reviews OE and incorporates applicable industry OE into the program. PBN will continue to monitor industry OE, including Westinghouse InfoGrams and Technical Bulletins and NRC Information Notices and Regulatory Issue Summaries so that the PBN Cracking of Nickel Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP will continue to be effective during the SPEO.

Plant Specific Operating Experience

A listing of Alloy 600 components that have been replaced at PBN due to PWSCC, or concerns thereof, is included as Attachment A of the Alloy 600 Management Program procedure. These include new RVHs for both Units 1 and 2 in 2005. On February 11, 2003, the NRC issued Order EA-03-009 to licensees operating PWRs. The Order established a minimum set of RVH inspections based on susceptibility categories. Included as part of the Order for those plants in the High Susceptibility Category (applicable to PBN Units 1 and 2 prior to RVH replacement) were requirements for bare metal visual examination of 100 percent of the RVH surface and either UT examination of the RVH penetrations, or eddy current testing (ECT) or dye penetrant testing of the wetted surface of each J-Grove weld and RVH penetration nozzle base material. These inspections were required to be performed every refueling outage. PBN has since replaced the RVH on both units with new assemblies fabricated from less susceptible materials as a cost-effective way of addressing the issue.

Additional self-assessments and post-approval NRC inspections have identified the following:

- Level 1, License Renewal Aging Management Program Effectiveness Review

  This assessment performed a review of the effectiveness of Point Beach License Renewal Aging Management Programs.

  In regard to the PBN Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP, the following actions were identified:

  - Add additional bases references and implementing documents.

  - Add the implementing procedure(s) as a reference in the fleet procedure and specify a requirement to initiate an item into the corrective action program when results fail to meet acceptance criteria.

  - Formally document OE reviews.

These actions have all been completed.

All License Renewal programs were judged to still be effective. No ineffective programs were identified.

- Phase 2 Point Beach Nuclear Plant Unit 1 and Unit 2 NRC Post-Approval Site Inspection Reports for License Renewal

  With regard to the PBN Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP, the NRC reviewed the licensing basis, program basis document, implementing procedures, assessments, and related condition reports; and interviewed the plant personnel responsible for the AMPs. The NRC verified that program implementing documents contain the appropriate License Renewal references.

Based on review of the timeliness and adequacy of PBN's actions, the NRC concluded that program commitments were properly met.

To assess effectiveness of AMPs credited for subsequent license renewal, the AMPs are reviewed against the criteria provided in NEI 14-12. The most recent effectiveness review of Aging Management Programs at PBN was performed in 2018. The effectiveness review covered the applicable ten program elements with particular attention on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). Full AMP effectiveness reviews are performed at least every five years.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP, with enhancement, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended functions of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

Program Description

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP is a new AMP that provides reasonable assurance that reactor coolant pressure boundary CASS components susceptible to thermal aging embrittlement, will continue to perform their intended function consistent with the CLB during the SPEO. The American Society of Mechanical Engineers (ASME) Code Class 1 components, including CASS components, are maintained by inspecting and evaluating their condition in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB. The PBN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1) will be supplemented by the new Thermal Aging Embrittlement of CASS AMP which monitors loss of fracture toughness due to thermal embrittlement for ASME Code Class 1 CASS components with service conditions above 482°F.

The RCS components are inspected in accordance with the ASME Code Section XI. This inspection is supplemented to detect the effects of loss of fracture toughness due to thermal aging embrittlement of CASS piping components except for pump casings and valve bodies. The PBN Thermal Aging Embrittlement of CASS AMP includes determination of the potential significance of thermal aging embrittlement of CASS components based on casting method, molybdenum content, and percent ferrite. For components susceptible to thermal aging embrittlement as defined in NUREG-2191, Section XI.M12, aging management is accomplished through one of the following:

- Qualified visual inspections, such as enhanced visual examination (EVT-1);
- Qualified ultrasonic testing (UT) methodology; or
- Component-specific flaw tolerance evaluation in accordance with the ASME Code Section XI, 2007 Edition and addenda through 2008.

Additional inspections or evaluations to demonstrate that the material has adequate fracture toughness are not required for components not susceptible to thermal aging embrittlement. Applicable industry standards and guidance documents are used to develop this AMP.

The only CASS components at PBN that are susceptible to thermal aging embrittlement are located in the Reactor Coolant System where the operating temperature is above 482°F. These components are elbows in RCS piping, RCS system valve bodies, and reactor vessel internal components. RCS pump casings are also constructed of CASS but are not susceptible to thermal aging embrittlement based on Table XI.M12-1 of NUREG-2191.

PBN has chosen the evaluation method to disposition reduction in fracture toughness due to thermal embrittlement of primary loop elbows. PBN does not have CASS RCS piping, but does have CASS primary loop elbows. The component-specific flaw tolerance evaluation in SLRA Section 4.7.3 determined that the results for susceptible reactor coolant loop CASS piping elbows are acceptable for 80 years of plant operation. For valve bodies, screening for significance of thermal aging embrittlement is not required per NUREG-2191. The existing PBN ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD AMP (Section B.2.3.1) inspection requirements are adequate for RCS valve bodies. Additionally, the reactor vessel internal components that are fabricated from CASS are not within the scope of this AMP but are managed by the PBN Reactor Vessel Internals AMP (Section B.2.3.7). Also, while reactor coolant pump casings are not susceptible to thermal aging embrittlement, an SLR Code Case N-481 RCP integrity analysis has also been performed. PBN is not using Code Case N 481 since it was annulled per RG 1.147. However, the analysis that supported annulling the Code Case was based on 40 years plant life span. Thus, the Code Case N-481 flaw tolerance evaluation has been updated for 80 years and no further actions are needed to manage thermal aging embrittlement of the PBN RCP pump casings.

The PBN Thermal Aging Embrittlement of CASS AMP will be implemented no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PBN Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP will be consistent with the 10 elements of NUREG-2191, Section XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel” as modified by SLR-ISG-Mechanical-2020-XX, Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

PBN evaluates industry OE items for applicability per the NextEra Fleet OE Program and takes corrective actions, when necessary. The PBN Thermal Aging of CASS AMP is consistent with the NUREG-2191 XI.M12 AMP, which in turn is based on research data. Outside of this research data, there is little additional industry OE specific to thermal aging embrittlement in CASS components. Industry OE includes:

Surry Power Station:

- During the Unit 1 Spring 2015 Outage, a VT-3 visual exam was performed on the “C” Reactor Coolant Pump casing following removal of the pump for overhaul and turning vane bolt replacement. The VT-3 visual exam was satisfactory with no indications observed. A small quantity of loose debris was found in the discharge nozzle, was satisfactorily removed, and documented in a condition report.

- During the Unit 2 Fall 2015 Outage, a VT-3 visual exam was performed on the “A” Reactor Coolant Pump casing following removal of the pump for overhaul and turning vane bolt replacement. The VT-3 visual exam was satisfactory with no indications observed.

Peach Bottom Atomic Power Station:

- In 2003, on Unit 3, the “A” reactor recirculation pump internal surfaces were inspected, and in 2007, the “B” reactor recirculation pump internal surfaces were inspected. The visual inspections (VT-3) were performed during the replacement of the pump internals in accordance with ASME Code Section XI, Table IWB-2500-1, Item No. B12.20, Pump Casing, (B-L-2). No recordable indications were identified on either pump.

<u>Plant Specific Operating Experience</u>

The PBN Thermal Aging Embrittlement of CASS AMP is a new program for PBN that is to be implemented no later than 6 months prior to the SPEO. Therefore, there is no existing OE to validate the effectiveness of this AMP at PBN. A review of Action Reports (ARs) at the site did not result in any CASS component issues, including thermal aging embrittlement. No negative results have been identified in B-L-2 inspections (RCP casings). The CASS main loop elbows are ASME Category RI (Risk Informed), which was previously ASME Category B-J.

To assess effectiveness of AMPs credited for subsequent license renewal, the AMPs are reviewed against the criteria provided in NEI 14-12. The most recent effectiveness review of Aging Management Programs at PBN was performed in 2018. The effectiveness review covered the applicable ten program elements with particular attention on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). Full AMP effectiveness reviews are performed at least every five years.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B

Conclusion

The PBN Thermal Aging Embrittlement of CASS AMP will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of this new AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.7 Reactor Vessel Internals

Program Description

The PBN Reactor Vessel Internals AMP is an existing AMP with the following principal objectives:

- Manage the effects of age-related degradation mechanisms that are applicable to pressurized water reactor (PWR) reactor vessel internals (RVI) components including;
    - Cracking; stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC) irradiation-assisted stress corrosion cracking (IASCC), and cracking due to fatigue/cyclic loading
    - Loss of material induced by wear
    - Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement
    - Changes in dimension due to void swelling (VS) or distortion
    - Loss of preload due to thermal and irradiation-enhanced stress relaxation or creep
- This program will be enhanced to implement MRP-227 Revision 1-A as supplemented by the gap analysis or an NRC-approved version of MRP-227 which addresses 80 years of operation if one is available prior to the subsequent period of extended operation.

The PBN reactor vessel internals program for the current license renewal period is based on Electric Power Research Institute (EPRI) Technical Report No. 1022863, “Materials Reliability Program: Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines (MRP-227-A) and is implemented in accordance with Nuclear Energy Institute (NEI) 03-08, Revision 3, “Guideline for the Management of Materials Issues” (Reference 1.6.53). The staff approved the augmented inspection and evaluation (I&E) criteria for PWR reactor vessel internals components in NRC Safety Evaluation (SE), Revision 1, on MRP-227 by letter dated December 16, 2011 and the staff subsequently approved the PBN license renewal reactor vessel internals program report including all licensee action items, which is based on the guidance of MRP-227-A. The guidelines of MRP-227-A are based on an analysis of the reactor vessel internals that considers the operating conditions up to a 60-year operating period.

The PBN Reactor Vessel Internals AMP for SLR uses the most recent guidelines of EPRI Technical Report No. 3002017168, MRP-227 Revision 1-A as the baseline to address an 80-year operating period. Revision 1 of these guidelines provides updates based on the Nuclear Regulatory Commission (NRC) Safety Evaluation Report (SER) for MRP-227 Revision 0, as well as operating experience and new knowledge gained from various materials testing, modeling, and research. Revision 1-A of these guidelines incorporates changes from the NRC SER for MRP-227 Revision 1. MRP-227 Revision 1-A still only addresses an operating period of 60 years and will be implemented at PBN for the current period of extended operation by January 1, 2022 per the NEI 03-08 implementation protocol. To facilitate implementing the guidance in MRP-227 Revision 1-A and recognize the necessary changes to align the current PBN reactor vessel internals program with this guidance, the tables in Section C.5.0 in Appendix C of this application identifies the changes made in MRP-227 Revision 1-A as compared to MRP-227-A. In this program, the term “MRP-227 Revision 1-A (as supplemented by a gap analysis)” is used to describe MRP-227 Revision 1-A as supplemented by the 60 to 80-year gap analysis presented in Appendix C of this SLRA.

The PBN Reactor Vessel Internals AMP applies the guidance in MRP-227 Revision 1-A (as supplemented by a gap analysis) for inspecting and evaluating reactor vessel internals components at PBN. These examinations provide reasonable assurance that the effects of age-related degradation mechanisms will be managed during the SPEO. This program includes expanding periodic examinations and other inspections, if the extent of the degradation identified exceeds the expected levels.

MRP-227-1-A provides guidance for selecting reactor vessel internals components for inclusion in the inspection sample. Through this process, the reactor vessel internals were assigned to one of the following four groups: Primary, Expansion, Existing Programs, and No Additional Measures. Definitions of each group are provided in MRP-227 Revision 1-A.

A set of Primary RVI component locations are inspected because they are highly susceptible to the effects of at least one of the eight aging mechanisms identified above. Another set of Expansion RVI component locations are specified to expand the inspection sample should the Primary Component indications be more severe than anticipated.

A third set of RVI component locations, Existing Programs components, are susceptible to the effects of at least one of the eight aging mechanisms and are deemed to be adequately managed by Existing Programs, such as American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, Examination Category B-N-3, examinations of core support structures.

A fourth set of RVI component locations are deemed to require No Additional Measures, for which the effects of all eight aging mechanisms are below the screening criteria as demonstrated in MRP-191 Revision 2.

Based on the results of the gap analysis for the 60- to 80-year operating period, four RVI component locations are added to the Primary Components inspection category in addition to those identified in MRP-227-1-A. Two of these components are new additions to the PBN Reactor Vessel Internals AMP; the clevis insert dowels and radial support keys. The clevis insert bolts are escalated from the Existing Programs inspection category. The clevis insert Stellite wear surface is a new addition to the MRP-227 Revision 1-A Existing Programs inspection category and is escalated to the Primary Components inspection category by the guidance in MRP 2018-022.

Two RVI component locations are added to the Existing Programs inspection category. The upper and lower core plate fuel alignment pins are added per the MRP 2018-022 guidance. The CRDM thermal sleeves are recommended to be added to the Primary Components inspection category per MRP 2018-022. However, the recent industry operating experience regarding thermal sleeve flange wear is not applicable to PBN as the site specific design will limit flange wear and prevent flange separation per NSAL-18-1 (Reference ML18198A275). As such, the CRDM thermal sleeves are added to the No Additional Measures inspection category.

The PBN Reactor Vessel Internals AMP relies on the PBN Water Chemistry AMP (Section B.2.3.2) to prevent or mitigate aging effects that can be induced by corrosive aging mechanisms. For the management of cracking, the PBN Reactor Vessel Internals AMP monitors for evidence of surface-breaking linear discontinuities if a visual inspection technique is used as the non-destructive examination (NDE) method or for relevant flaw presentation signals if a volumetric ultrasonic testing (UT) method is used as the NDE method. For the management of loss of material, the AMP monitors for gross or abnormal surface conditions that may be indicative of loss of material occurring in the components. For the management of loss of preload, the AMP monitors for gross surface conditions that may be indicative of loosening in applicable bolted, fastened, keyed, or pinned connections. The AMP does not directly monitor for loss of fracture toughness that is induced by thermal aging or neutron irradiation embrittlement. Instead, the impact of loss of fracture toughness on component integrity is indirectly managed by: (1) using visual or volumetric examination techniques to monitor for cracking in the components, and (2) applying applicable reduced fracture toughness properties in the flaw evaluations, in cases where cracking is detected in the components and is extensive enough to necessitate a supplemental flaw growth or flaw tolerance evaluation. The AMP uses physical measurements to monitor for any dimensional changes due to void swelling or distortion.

The inspection methods are determined in accordance with MRP-228 (Reference 1.6.54). The PBN Reactor Vessel Internals AMP will be enhanced to align the examination method, frequency, and examination coverage to those in MRP-227 Revision 1-A (as supplemented by a gap analysis). In all cases, well-established inspection methods are selected. These methods include volumetric UT examination methods for detecting flaws in bolting and various visual examinations (VT-3, VT-1, and EVT-1) for detecting effects ranging from general conditions to detection and sizing of surface-breaking discontinuities. Surface examinations may also be used as an alternative to visual examinations for detection and sizing of surface-breaking discontinuities.

Cracking caused by SCC, IASCC, PWSCC, and fatigue is monitored/inspected by either VT-1 or EVT-1 examination (for internals other than bolting) or by volumetric UT examination (bolting). VT-3 visual methods may be applied for the detection of cracking in non-redundant RVI components only when the flaw tolerance of the component, as evaluated for reduced fracture toughness properties, is known and the component has been shown to be tolerant of easily detected large flaws, even under reduced fracture toughness conditions. VT-3 visual methods are acceptable for the detection of cracking in redundant RVI components (e.g., redundant bolts or pins used to secure a fastened RVI assembly).

In addition, VT-3 examinations are used to monitor/inspect for loss of material induced by wear and for general aging conditions, such as gross distortion caused by VS and irradiation growth, or by gross effects of loss of preload caused by thermal and irradiation-enhanced stress relaxation and creep. In some cases (as defined in

MRP-227 Revision 1-A), physical measurements are used as supplemental techniques to manage for the gross effects of wear, loss of preload due to stress relaxation, or for changes in dimensions due to VS or distortion.

The PBN Reactor Vessel Internals AMP adopts the guidance in MRP-227 Revision 1-A (as supplemented by a gap analysis) for defining the Expansion Criteria that need to be applied to the inspection findings of Primary Components and for expanding the examinations to include additional Expansion components. Reactor vessel internals component inspections will be performed consistent with the inspection frequency and sampling bases for Primary Components, Existing Programs components, and Expansion components in MRP-227 Revision 1-A (as supplemented by a gap analysis). No new Primary Components have links to Expansion components. The timing of baseline examinations for 60 to 80 years of operation, remain unchanged from the MRP-227 Revision 1-A tables for 40 to 60 years of operation and inspection intervals for new Primary Components remain unchanged from the continuation of ASME Section XI inspection intervals.

The PBN Reactor Vessel Internals AMP applies applicable fracture toughness properties, including reductions for thermal aging or neutron embrittlement, in the flaw evaluations of the components in cases where cracking is detected in a RVI component and is extensive enough to warrant a supplemental flaw growth or flaw tolerance evaluation.

For singly-represented components, the PBN Reactor Vessel Internals AMP includes criteria to evaluate the aging effects in the inaccessible portions of the components and the resulting impact on the intended function(s) of the components. For redundant components (such as redundant bolts, screws, pins, keys, or fasteners, some of which are accessible to inspection and some of which are not accessible to inspection), the AMP includes criteria to evaluate the aging effects in the population of components that are inaccessible by the applicable inspection technique and the resulting impact on the intended function(s) of the assembly containing the components. The acceptance criteria for inspections fall into one of the following two categories:

- For visual examination (and surface examination as an alternative to visual examination), the examination acceptance criterion is the absence of any of the specific, descriptive relevant conditions; in addition, there are requirements to record and disposition surface breaking indications that are detected and sized for length by VT-1/EVT-1 examinations.

- For volumetric examination, the examination acceptance criterion is the capability for reliable detection of indications in bolting, as demonstrated in the examination technical justification; in addition, there are requirements for system-level assessment of bolted or pinned assemblies with unacceptable volumetric (UT) examination indications that exceed specified limits.

This AMP follows corrective action procedures consistent with NEE fleet guidance. Any conditions found, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, measures are implemented to determine the cause of the condition and take corrective action to prevent recurrence. These measures may include engineering evaluations, supplementary examinations, repair, or replacement. Any repair or replacement activities are subject to ASME Code Section XI requirements.

NUREG-2191 Consistency

The PBN RVI AMP, with enhancements, will be consistent with an exception with the program described in NUREG-2191, Section XI.M16A.

Exceptions to NUREG-2191

The program described in NUREG-2191, Section XI.M16A provides MRP-227-A as the basis for a site specific RVI program. The scope of the PBN Reactor Vessel Internals AMP applies the methodology and guidance in MRP-227 Revision 1-A (as supplemented by a gap analysis). MRP-227 Revision 1-Ais the most recent NRC approved guidance for managing PWR vessel internals and incorporates significant recent operating experience.

Enhancements

The PBN RVI AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	The AMP will be enhanced to implement MRP-227 Revision 1-A as supplemented by the gap analysis or an NRC-approved version of MRP-227 which addresses 80 years of operation if one is available prior to the subsequent period of extended operation.
5. Monitoring and Trending	The examination and re-examination schedules in the AMP will be enhanced to be implemented in accordance with MRP-227 Revision 1-A (as supplemented by a gap analysis).
6. Acceptance Criteria	The AMP will be enhanced to incorporate the updated examination acceptance criteria, Primary / Expansion links, expansion criteria, and expansion item examination criteria in MRP-227 Revision 1-A.

Operating Experience

Industry Operating Experience

PBN evaluates industry operating experience (OE) for applicability in accordance with the NextEra Fleet OE Program and takes corrective actions, when necessary. As identified below, industry operating experience is integral to the PBN Reactor Vessel Internals AMP. Tracking of active degradation mechanisms informs the program on potential issues which are evaluated for potential augmented inspections or material modifications. Four components with significant degradation indications throughout the industry have been identified, evaluated and dispositioned for relevance to PBN:

Baffle Bolting

A higher than expected incidence of baffle bolt degradation was observed at Indian Point, Cook, and Salem involving 4-loop downflow plant designs with internal hex+lock-bar bolt design and type 347SS material. A Westinghouse 2-loop plant like PBN has more baffle bolts per square inch of baffle plate, resulting in lower primary stresses compared to the 4-loop designs. Further, PBN converted from a downflow to an upflow design, which produces smaller differential pressure across the baffle plates, resulting in lower bolt loads.

EPRI released interim guidance in MRP 2017-009 regarding baffle bolt inspections as defined in NSAL-16-01. PBN evaluated this guidance and noted that it is a Tier 3 plant based on the guidance. PBN had already completed baseline inspections of the baffle former bolts but will be implementing the expansion criteria guidance during the reinspection interval.

EPRI further released guidance through MRP 2017-035 and MRP 2018-002. PBN is participating in the industry efforts to provide baffle bolt inspections to the NRC. PBN had completed all baseline baffle former bolt inspections at the time of publication of MRP 2018-002. However, PBN implemented the interim guidance per the NEI 03-08 implementation protocol for future inspections.

Fuel Alignment Pins

Westinghouse released a technical bulletin, TB 16-4, “Fuel Alignment Pin Malcomized Surface Degradation”, which identified PBN as being potentially susceptible to surface degradation of the fuel alignment pins in both the upper core plate and lower core plate. Following the issuance of TB 16-4, PBN evaluated the impact to the site. Westinghouse evaluated the potential degradation of the malcomized fuel alignment pins in the upper core plate and lower core plate at PBN and concluded that the plant operates with sufficient margin that continued operation would not result in any violation of any limits and no further evaluation is required. The PBN subsequent license renewal gap analysis in Appendix C to this SLRA adds these components to the Primary Component inspection category.

Guide Cards

Accelerated wear of guide cards was identified by the industry Issue Program who released industry inspection information that identified higher wear than expected during inspections of the Control Rod Guide Tube (CRGT) guide cards through MRP 2016-035. PBN evaluated this to have no impact on the inspections at PBN, which had already completed the baseline inspections at both units with inspection coverage of 100 percent of the CRGT. However, PBN implemented the interim guidance per the NEI 03-08 implementation protocol for future inspections.

In 2018 EPRI released NEI 03-08 “Needed” interim guidance regarding guide card wear inspection schedules in MRP 2018-007. PBN had completed all baseline guide card inspections and no immediate actions were necessary. This interim guidance did not directly impact PBN because it had already completed the baseline inspections of the guide cards. Re-evaluation results applying WCAP-17451 Revision 1 supported moving the re-inspection of the limiting guide tubes within each unit by at least one additional outage. The re-inspection of the guide cards is currently scheduled during 2022 and 2023. These inspections are subject to this interim guidance.

Clevis Insert

Westinghouse technical bulletin, TB 14-5, was issued to communicate industry operating experience regarding clevis insert cap screw degradation observed during ASME Section XI inspections. This was evaluated by PBN and the site updated the implementing procedure to incorporate the guidance in TB 14-5.

EPRI released a notification of industry operating experience regarding clevis insert bolting in MRP 2017-024. This letter identified degradation of the clevis insert bolting at Salem Unit 2 during its spring 2017 outage. PBN evaluated this OE and determined there were no changes needed to the PBN Reactor Vessel Internals AMP.

EPRI issued a notification of recent operating experience, MRP 2020-011 to document a partial displacement observed at one lower radial support clevis insert. PBN evaluated this OE and determined there are no recommended actions to implement changes in the aging management program for the initial license renewal period. For subsequent license renewal, the clevis insert bolts, dowels, and clevis bearing Stellite wear surface are added to the Primary Components inspection category per the results of the gap analysis (Appendix C to this SLRA).

Developing Industry Operating Experience

Westinghouse technical bulletin TB 19-5 and corresponding MRP 2019-017 were issued to document a developing asset management concern of cracking in thermal shield support structures. These notices were identified as applicable to PBN. This is a developing issue which will continue to be followed by PBN.

EPRI issued industry letter MRP 2019-009, which communicates the issuance of NEI 03-08 “Good Practice” guidance for the core barrels in Westinghouse plants and was transmitted to the NRC through MRP 2019-023. The recommended good practice is to inspect the core barrel axial welds (middle axial weld and lower axial weld). PBN noted that the baseline inspections of the core barrel have already been performed, and the next planned inspections are during the Spring 2022 and Spring 2023 refueling outages for Unit 1 and Unit 2, respectively. PBN implements all NEI 03-08 “Good Practices” when feasible. Note that implementation of MRP-227 Revision 1-A will incorporate these welds as Expansion components prior to the scheduled outages.

EPRI issued industry letter MRP 2019-002, which provides interim guidance to MRP-227-A for Westinghouse plants implementing "Flexible Power Operations,". Upon review of applicability to PBN, PBN has not implemented flexible power operations and has no plans to implement flexible power operations in the future. The load following operations in the early life of PBN do not impact this guidance. As such, this letter is not applicable to PBN.

Plant Specific Operating Experience

- PBN has inspected 100 percent of CRGT guide cards on both units as a part of its baseline inspections. The results of these inspections were evaluated based on the methodology described in WCAP-17451 Revision 1 and reinspection or repair of one limiting guide tube within each tube was recommended for the 2020 refueling outages. The publishing of WCAP-17451 Revision 2 prompted a re-evaluation to potentially extend the reinspection interval of the limiting guide tube to align with the re-inspection timing of the other guide tubes. Re-evaluation was performed using both methods (WCAP-17451-P Revision 1 and Revision 2) and only the results applying WCAP-17451 Revision 1 were used because the methodology in WCAP-17451 Revision 2 has not been endorsed by the NRC at this time. Additionally, PBN has spare CRGTs to support any repair activities if needed.

- PBN Units 1 and 2 have completed all MRP-227-A initial license renewal required inspections with no inspection deferrals and no deviations to NEI 03-08. All baseline inspections completed were performed prior to loss of safety function which demonstrates that the inspection timing defined in MRP-227-A has been adequate and the PBN Water Chemistry AMP (Section B.2.3.2) has sufficiently prevented or mitigated accelerated aging effects. All degradation identified has been consistent with industry experience resulting in acceptable results for all inspections. There has not been an examination which required Expansion Components inspections.

- Program Assessments and Evaluations

  - Phase 2 Point Beach Nuclear Plant, Unit 1 and Unit 2 NRC Post-Approval Site Inspection Reports for License Renewal (ADAMS Accession no. ML102850469 and ML13077A472)

    In 2010 and 2013, the NRC performed the 71003 Phase 2 Inspections at PBN Units 1 and 2, respectively. The inspectors reviewed the licensing basis, program basis document, implementing procedures, and related ARs; and interviewed the plant personnel responsible for the PBN Reactor Vessel Internals AMP. The inspectors verified that the program meets current industry guidance and tracking is in place for incorporating any changes resulting from NRC review of the industry guidance. Based on review of the timeliness and adequacy of PBN's actions, the inspectors determined that the PBN had met all commitments.

  - Level 1 License Renewal Aging Management Program Effectiveness Review

    In 2018, an effectiveness review of the PBN Reactor Vessel Internals AMP was performed following the guidelines provided in NEI 14-12. The effectiveness review covered the applicable ten program elements. There were no gaps identified and the effectiveness review found the PBN Reactor Vessel Internals AMP continued to be effectively implemented. AMP effectiveness reviews are performed at least every five years.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Reactor Vessel Internals AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Reactor Vessel Internals AMP, with exception and enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.8 Flow-Accelerated Corrosion

Program Description

The PBN Flow-Accelerated Corrosion AMP is an existing AMP that manages wall thinning caused by flow-accelerated corrosion (FAC), as well as wall thinning due to erosion mechanisms. This AMP is based on commitments made in response to NRC Generic Letter 89-08, "Erosion/Corrosion Induced Pipe Wall Thinning," and relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center, NSAC-202L-R4 (Reference 1.6.55) for an effective FAC program.

This AMP includes the following:

a. Identifying all FAC-susceptible piping systems and components;
b. Developing FAC predictive models to reflect component geometries, materials, and operating parameters;
c. Performing analyses of FAC models and, with consideration of OE, selecting a sample of components for inspections;
d. Inspecting components;
e. Evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and
f. Incorporating inspection data to refine FAC models.

The PBN FAC AMP monitors the effects of wall thinning due to FAC and erosion mechanisms by measuring wall thicknesses. Relevant changes in system operating parameters, (e.g., temperature, flow rate, water chemistry, operating time), including the EPU implemented in 2011, and other conditions resulting from off normal or reduced power operations, are considered for their effects on the predictive analytical software such as CHECWORKS™, and these parameters are included in updates to the software where applicable. Opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation. Components are suitable for continued service if calculations determine that the predicted wall thickness at the next scheduled inspection (after next operating cycle) will meet the minimum allowable wall thickness. The minimum allowable wall thickness is the thickness needed to satisfy the component design loads under the original code of construction; additional code requirements are met, as applicable. A conservative safety factor is applied to the predicted wear rate determination to account for uncertainties in the wear rate calculations and UT measurements as recommended by NSAC 202L R4.

The PBN FAC AMP procedures require reevaluation, repair, or replacement of components for which the acceptance criteria are not satisfied, prior to their return to service. For FAC, long-term corrective actions may include replacing components with FAC-resistant materials. Operating parameters that affect predicted FAC wear rates (e.g., operating time, hydrodynamic conditions, water treatment, component material, etc.) may also be adjusted, as long as the corresponding predictive analytical software (i.e. CHECWORKS™) models are also updated. When carbon steel (steel) piping components are replaced with FAC-resistant material, the susceptible components immediately downstream are considered for monitoring to identify any increased wall thinning.

The PBN FAC AMP also manages wall thinning caused by erosion mechanisms where periodic monitoring is used in lieu of eliminating the cause, typically a design or operational deficiency, in components that contain treated water (including borated water) or steam. These limited situations are based on site OE and will be monitored similar to other FAC locations that are not modeled.

The PBN FAC AMP is a condition monitoring program. With that noted, the rate of FAC or erosion, where applicable, is affected by piping material, geometry and hydrodynamic conditions, and operating conditions such as temperature, pH, steam quality, operating hours, and dissolved oxygen content. Preventive action is taken in response to conditions identified from the results of the FAC program inspections. These actions are driven by the corrective action program.

NUREG-2191 Consistency

The PBN Flow-Accelerated Corrosion AMP, with enhancement, will be consistent with the 10 elements of NUREG-2191, Section XI.M17, "Flow-Accelerated Corrosion."

Exceptions to NUREG-2191

None.

Enhancements

The PBN Flow-Accelerated Corrosion AMP will be enhanced as follows for alignment with NUREG-2191. Enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	• Reassess piping systems excluded from wall thickness monitoring due to operation less than 2 percent of plant operating time (as allowed by NSAC-202L) to ensure the exclusion remains valid and applicable for operation beyond 60 years. • Formalize a separate erosion susceptibility evaluation (ESE) that will include all components determined to be susceptible to wall loss due to erosion through OE and industry guidance.

4. Detection of Aging Effects	• Perform or compile baseline inspections of erosion susceptible locations where site OE indicates periodic monitoring may be warranted instead of design or operational correction to eliminate the cause of erosion.
	• Revise or develop procedural guidance relative to erosion based on the results that includes –
	  o Components treated in a manner similar to "susceptible-not-modeled" lines discussed in NSAC-202L.
	  o Consideration of EPRI 1011231 for identifying potential damage locations and EPRI TR-112657 and/or NUREG/CR–6031 guidance for cavitation erosion as warranted.

Element Affected	Enhancement
5. Monitoring and Trending	• Revise or provide procedure(s) for measuring wall thickness due to erosion. Wall thickness should be trended to adjust the monitoring frequency and to predict the remaining service life of the component for scheduling repairs or replacements. • Revise or provide procedure(s) to evaluate inspection results to determine if assumptions in the extent-of-condition review remain valid. If degradation is associated with infrequent operational alignments, such as surveillances or pump starts/stops, then trending activities should consider the number or duration of these occurrences. • Revise or provide procedure(s) to perform periodic wall thickness measurements of replacement components until the effectiveness of corrective actions have been confirmed.
7. Corrective Actions	• Include long-term corrective actions for erosion mechanisms. The effectiveness of the corrective actions should be verified. Include periodic monitoring activities for any component replaced with an alternative material since no material is completely resistant to erosion.

Operating Experience

Industry Operating Experience

Outage inspection plans for the PBN FAC AMP consider pertinent industry operating experience, such as from NRC Information Notice (IN) 2006 08. Inspections and verifications of susceptible lines have been performed based on OE through evaluation and inspection plan adjustment and programmatic improvements made at PBN.

Ginna, a sister plant of PBN, completed an EPU in 2006. The only area they have experienced higher wear rates is the cross under piping from the HP Turbine to the Moisture Separator Reheaters. PBN inspects the same lines each outage.

Susceptible components to FAC and erosion can be identified through OE and industry guidance. Industry experience has shown that some non-susceptible to FAC lines may need to be included in the program due to adverse or abnormal operating conditions (e.g., minimum flow lines, emergency drains, start-up lines kept open due to operating problems). Sufficient information should be provided to document the susceptibility conclusions in the SSE or ESE and be updated to include the addition and/or deletion of systems as required by plant or industry experience; or as justified by inspection results or material replacement.

Plant Specific Operating Experience

A review of plant operating experience indicates that numerous work orders, condition reports/action requests have been issued as a result of the discovering flow-accelerating corrosion.

The PBN Flow-Accelerated Corrosion AMP is a mature, established program. The effectiveness of the PBN FAC AMP has been demonstrated as a result of the

October 2010 and March 2013 NRC Phase 2 post-approval site inspections which were conducted prior to entering into the original PEO for each unit. The inspectors reviewed the licensing basis, program basis document, implementing procedures, and completed inspections; and interviewed the PBN plant personnel responsible for this program. The inspectors verified that program and associated enhancements were in place. Based on review of the timeliness and adequacy of PBN's actions, the inspectors determined PBN had met the required commitments for the PBN FAC AMP.

In 2018, an effectiveness review of the PBN FAC AMP was performed following the guidelines provided in NEI 14-12. The effectiveness review covered the applicable ten program elements with focuses on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). In response to the AMP effectiveness review, LR AMP Basis Document was updated to include the new revision of EPRI guidelines, NSAC-202L-R4, and to update FAC procedures. PBN FAC AMP was determined to continue to be effectively implemented, and there were no gaps identified for this program.

Inspection results from 2010 through the most recent inspections have indicated that the loss of material is within the range of expectation. Outage inspections performed in 2017 (U1R37), 2018 (U2R36) and 2019 (U1R38) specified whether the inspection results were satisfactory and provided further mitigating actions or re-evaluation for components that did not meet the screening criteria. The inspections demonstrated that the program was effective in identifying and mitigating FAC degradation.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Flow-Accelerated Corrosion AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Flow-Accelerated Corrosion AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.9 Bolting Integrity

Program Description

The PBN Bolting Integrity AMP is an existing AMP that manages loss of preload, cracking, and loss of material for closure bolting for safety-related and nonsafety-related pressure-retaining components using preventive and inspection activities. This AMP also manages submerged pressure-retaining bolting and closure bolting for piping systems that contain air or gas for which leakage is difficult to detect.

Applicable industry standards and guidance documents relevant to this AMP include NUREG-1339 (Reference 1.6.56), "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," EPRI NP-5769 (Reference 1.6.57), "Degradation and Failure of Bolting in Nuclear Power Plants," EPRI Report 1015336 (Reference 1.6.58), "Nuclear Maintenance Application Center: Bolted Joint Fundamentals," and EPRI Report 1015337 (Reference 1.6.59), "Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints."

The preventive actions associated with this AMP include proper selection of bolting material; the use of appropriate lubricants and sealants in accordance with the guidelines of EPRI Report 1015336 and EPRI Report 1015337, along with additional recommendations from NUREG-1339; consideration of actual yield strength when procuring bolting material (e.g., ensuring any replacement or new pressure-retaining bolting has an actual yield strength of less than 150 ksi); lubricant selection (e.g., not allowing the use of molybdenum disulfide); proper torqueing of bolts, checking for uniformity of the gasket compression after assembly; and application of an appropriate preload based on guidance in EPRI documents, manufacturer recommendations, or engineering evaluation.

The PBN Bolting Integrity AMP provides inspection of pressure-retaining bolting per ASME Code requirements. Pressure-retaining bolted connections are inspected at least once per refueling cycle as part of ASME Code Section XI leakage tests. Inspections are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Non-ASME Code inspections follow site procedures that include inspection parameters for items such as lighting and distance offset that provide an adequate examination.

This AMP supplements the inspection activities required by ASME Code Section XI for ASME Code Class 1, 2 and 3 bolting. For ASME Code Class 1, 2, and 3, and non ASME Code class bolts, periodic system walkdowns and inspections are performed at least once per refueling cycle to provide reasonable assurance that indications of loss of preload (leakage), cracking, and loss of material are identified before leakage becomes excessive. Visual inspection methods and the frequency of inspection are selected to manage such effects to prevent significant age related degradation. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the CAP.

The inspection includes a representative sample of 20 percent of the population of bolt heads and threads (defined as bolts with the same material and environment combination) up to a maximum of 19 per unit (the environments of Units 1 and 2 have been determined to be similar).

Submerged closure bolting that precludes detection of joint leakage is inspected visually for loss of material during maintenance activities. Bolt heads are inspected when made accessible and bolt threads are inspected when joints are disassembled. In each 10-year period during SPEO, a representative sample of bolt heads and threads is inspected. If opportunistic maintenance activities do not provide access to 20 percent of the population (for a material/environment combination) up to a maximum of 19 per unit, then the integrity of the bolted joint will be evaluated on a case-by-case basis using methods, such as periodic pump vibration measurements taken and trended or sump pump operator walkdowns performed to demonstrate that the pumps are appropriately maintaining sump levels.

Because leakage is difficult to detect for bolted joints that contain air or gas, the associated closure bolting will be evaluated on a case-by-case basis using one of the following methods:

- Inspections are performed consistent with that of submerged closure bolting.
- A visual inspection for discoloration is conducted (applies when leakage of the environment inside the piping systems would discolor the external surfaces).
- Monitoring and trending of pressure decay is performed when the bolted connection is located within an isolated boundary.
- Soap bubble testing is performed.
- Thermography testing is performed (applies when the temperature of the fluid is higher than ambient conditions).

For component joints that are not normally pressurized, the aging effects associated with closure bolting will be managed by checking the torque to the extent that the closure bolting is not loose.

Indications of aging are evaluated in accordance with Section XI of the ASME Code. Leaking joints do not meet acceptance criteria.

NUREG-2191 Consistency

The PBN Bolting Integrity AMP, with enhancements, will be consistent with the program described in NUREG-2191, Section XI.M18.

Exceptions to NUREG-2191

None.

Enhancements

The PBN Bolting Integrity AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions 7. Corrective Actions	Enhance plant procedures to replace references to NP-5067 Volumes 1 and 2 and EPRI TR-104213 with EPRI Reports 1015336 and 1015337 and incorporate the guidance as appropriate.
2. Preventive Actions	Enhance plant procedures to ensure MoS_2 lubricant will not be used for pressure retaining bolting.
2. Preventive Actions 3. Parameters Monitored or Inspected 4. Detection of Aging Effects	Enhance plant procedures to ensure bolting material with a yield strength greater than or equal to 150 ksi (1,034 MPa) or for which yield strength is unknown will not be used in pressure retaining bolting. If closure bolting greater than 2 inches in diameter (regardless of code classification) with actual yield strength greater than or equal to 150 ksi (1,034 MPa) or for which yield strength is unknown is used, volumetric examination will be required in accordance to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 acceptance standards, extent, and frequency of examination.
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Create a new plant procedure to perform alternative means of testing and inspection for closure bolting where leakage is difficult to detect (e.g., piping systems that contain air or gas or submerged bolting). The acceptance criteria for the alternative means of testing will be no indication of leakage from the bolted connections. Required inspections will be performed on a representative sample of the population (defined as the same material and environment combination) of bolt heads and threads over each 10-year period of the SPEO. The representative sample will be 20% of the population (up to a maximum of 19 per unit);
4. Detection of Aging Effects	Enhance plant procedures and include in the new procedure the requirement to ensure that bolted joints that are not readily visible during plant operations and refueling outages will be inspected when they are made accessible and at such intervals that would provide reasonable assurance the components' intended functions are maintained. Plant procedures for visual inspections and examinations will be revised to include the bolting integrity program in their scope.
5. Monitoring and Trending	Enhance plant procedures and include in the new procedure the requirement to project, where practical, identified degradation until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. For sampling-based inspections, results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of

	degradation. Adverse results will be evaluated to determine if an increased sample size or inspection frequency is required
7. Corrective Actions	Enhance plant procedures and include in the new procedure the requirements for leakage monitoring, sample expansion and additional inspections if inspection results do not meet acceptance criteria.

Operating Experience

Industry Operating Experience

Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, SCC, and fatigue loading (NRC Inspection and Enforcement Bulletin (IEB) 82-02, NRC Generic Letter (GL) 91-17). SCC has occurred in high strength bolts used for nuclear steam supply system component supports (EPRI NP-5769). The bolting integrity program developed and implemented in accordance with the applicant's docketed responses to the U.S. Nuclear Regulatory Commission (NRC) communications on bolting events have provided an effective means of ensuring bolting reliability. These programs are documented in EPRI Reports NP-5769, 1015336, and 1015337 and represent industry consensus. The PBN Bolting Integrity AMP incorporates the recommended actions.

NRC Information Notice (IN) 2012-15, issued August 9, 2012, discusses issues related to the use of seal cap enclosures for mitigating leakage from joints that use A-286 bolts. In the two cases examined, bolts of this material were found to be vulnerable to stress corrosion cracking (SCC) as a result of the environment created by leakage into the seal cap. Through the CAP, NEE investigated the applicability of this issue to PBN and found that PBN does not have any seal caps installed.

Per the GALL-SLR, SCC has occurred in high strength bolts used for nuclear steam supply system component supports (EPRI NP-5769). Additionally, operating experience and laboratory examinations show that the use of molybdenum disulfide as a lubricant is a potential contributor to SCC. Based on investigation in response to an NRC request for information supporting license renewal for the current PEO, there is currently no high strength bolting within the scope of this program and molybdenum disulfide lubricant is not in use. The existing activities of this AMP will be enhanced to ensure that no new high strength bolting within the scope of this program will be installed and molybdenum disulfide will not be used as a lubricant.

Plant Specific Operating Experience

As discussed above, this program is supplemented by the PBN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP. See Section B.2.3.1 for additional discussion of site-specific OE associated with that AMP.

The following summary of site-specific OE (which includes review of corrective actions and NRC inspections) provides examples of how PBN is managing aging effects associated with the PBN Bolting Integrity AMP.

- While performing a maintenance activity, maintenance personnel noted leaks at two flange connections. The flanges were disassembled and inspected. Leakage at one of the flanges was a gasket/sealant selection issue which was promptly resolved. The other leak was at a cooler head to coolant line flange connection lower bolt hole. An inspection revealed cracks at the lower bolt holes.

  To address the cracking, specific requirements for torqueing the cooler head were incorporated into procedures to prevent recurrence. The repair proceeded as follows

  - Full depth studs w/Loctite were installed
  - Flange faces were checked for flatness and cleaned up as required
  - A flanged adapter to the cooler head was installed with a new gasket and torqued bolting to a maximum torque of 44 ft/lbs.
  - A replacement cooler head was ordered for installation during the next scheduled overhaul.

- A third-party review of two corrective actions related to a failed bolt on a pump indicated that an evaluation of the condition that caused the bolt failure was not performed. Only replacement of the bolt was specified. Accordingly, a corrective action was created to perform a license renewal evaluation of the failed bolt which ultimately determined that the bolt failure was not age-related. The failed bolt was found to have been necked down which contributed to its failure.

- There was a lubricating oil (LO) leak on the four bolt flange from the LO filter housing to the scavenging oil pump. The leak was about 6 drops of oil per hour falling onto the emergency diesel generator baseplate. The connection was removed, flanges ensured flat, and reassembled. The cause of the leak was determined to be related to the maintenance procedure which did not contain vendor recommended retorque instructions to be performed after one cycle. The procedures have been updated to address the issue.

- During performance of Appendix J Leak Rate Testing, leakage was 17,600 sccm. A walk down of the system found that an open valve had excessive leakage while snooping the body to bonnet diaphragm.

  During prior maintenance, workers had circled the incorrect torque values used from the bolting table which resulted in untorqueing. They had the torque for a 4-inch valve circled in the table and torqued to that value (195 in-lbs). The valve is a 3-inch valve. Torque value for a 3-inch valve is 300 in-lbs.

- Fuel oil was found leaking from the body to bonnet joint on a valve. Based on an inspection of the valve, the body to bonnet gasket was weeping around the bolt holes. The valve leak was repaired and the spilled fuel oil removed.

- In October 2010 and March 2013, the NRC completed post approval inspections for license renewal at PBN. For the bolting integrity AMP, no findings were identified and the inspectors determined that PBN had completed, or was on track to complete, the necessary tasks to meet the license renewal commitments, license conditions, and regulatory requirements.

- An AMP effectiveness review was performed in 2018 following the guidelines in NEI 14-12. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). The effectiveness review found that implementing documents reference the PBN Bolting Integrity AMP appropriately. The PBN Bolting Integrity AMP was determined to continue to be effectively implemented with no gaps identified.

- In 2019, the NRC performed the IP 71003 Phase 4 inspections at PBN Units 1 and 2. The PBN Bolting Integrity AMP was not one of the seven AMPs selected for review.

To date, no enhancements to the AMP have been identified as a result of OE. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Bolting Integrity AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Bolting Integrity AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.10 Steam Generators

Program Description

The PBN Steam Generators AMP, previously the PBN Steam Generator Integrity program, is an existing AMP that manages the aging of steam generator tubes, plugs, divider plate assemblies, heads (interior surfaces of channel or lower heads), tubesheet(s) (primary side), and secondary side components that are contained within the steam generator (i.e., secondary side internals). The aging of steam generator pressure vessel welds is managed by other AMPs such as the PBN ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1), and the PBN Water Chemistry AMP (Section B.2.3.2).

The establishment of a steam generator program for ensuring steam generator tube integrity is required by the PBN Technical Specifications (TS). Additionally, Administrative Control 5.6.8 requires tube integrity to be maintained to specific performance criteria, condition monitoring requirements, inspection scope and frequency, acceptance criteria for the plugging or repair of flawed tubes, acceptable tube repair methods, and leakage monitoring requirements. The non-destructive examination (NDE) techniques used to inspect steam generator components covered by this AMP are intended to identify components (e.g., tubes, plugs) with degradation that may need to be removed from service (e.g., tubes), repaired, or replaced, as appropriate.

The PBN Steam Generator AMP is based on the guidelines provided in NEI 97-06, Revision 3, “Steam Generator Program Guidelines.” As such, this AMP incorporates the following industry guidelines:

- EPRI 3002007572, “PWR Steam Generator Examination Guidelines” (Reference 1.6.60);
- EPRI 1022832, “PWR Primary-to-Secondary Leak Guidelines” (Reference 1.6.61);
- EPRI 3002000505, “Pressurized Water Reactor Primary Water Chemistry Guidelines”;
- EPRI 3002010645, “Pressurized Water Reactor Secondary Water Chemistry Guidelines”;
- EPRI 3002007571, “Steam Generator Integrity Assessment Guidelines” (Reference 1.6.62); and
- EPRI 3002007856, “Steam Generator In-Situ Pressure Test Guidelines” (Reference 1.6.63).

Through these guidelines, a balance of prevention, mitigation, inspection, evaluation, repair, and leakage monitoring measures are incorporated. Specifically, this AMP incorporates the following from NEI 97-06 (Reference ML111310708):

a. Performance criteria are intended to provide assurance that tube integrity is being maintained consistent with the CLB.
b. Guidance for monitoring and maintaining the tubes, which provides assurance that the performance criteria are met at all times between scheduled tube inspections.

Since degradation of divider plate assemblies, channel heads (internal surfaces), or tubesheets (primary side) may have safety implications, the PBN Steam Generators AMP addresses degradation associated with steam generator tubes, plugs, divider plates, interior surfaces of channel heads, tubesheets (primary side), and secondary side components that are contained within the steam generator (i.e., secondary side internals). This AMP does not include in its scope the steam generator secondary side shell, any nozzles attached to the secondary side shell or steam generator head, or the welds associated with these components. In addition, the scope of this AMP does not include steam generator primary side chamber welds (other than general corrosion of these welds caused as a result of degradation (defects/flaws) in the primary side cladding).

In July 2016, PBN submitted an application to amend the PBN Unit 1 Steam Generator Program as well as TS 3.4.13, 5.5.8 and 5.6.8. This application provided a technical justification to establish a permanent steam generator tube alternate repair criteria (H*) for tubing flaws located in the lower region of the tubesheet and accompanying inspection and reporting requirements. This application was reviewed and approved by the staff by letter dated July 27, 2017. This alternate repair criteria removes the tube-to-tubesheet weld from the credited pressure boundary and removes the inspection criteria for the portion of the tube below 20.6 inches from the top of the tubesheet.

The PBN Steam Generator AMP includes preventive and mitigative actions for addressing degradation. This includes foreign material exclusion as a means to inhibit wear degradation and secondary side maintenance/cleaning activities, such as sludge lancing, for removing deposits that may contribute to degradation. Sludge mapping occurs when the steam generator is inspected, and inspections for remaining foreign material are performed after sludge lancing is completed. Primary side preventive maintenance activities include replacing corrosion susceptible plugs with corrosion resistant materials and preventively plugging tubes susceptible to degradation. Additionally, this AMP works in conjunction with the PBN Water Chemistry AMP (Section B.2.3.2), which monitors and maintains water chemistry to reduce susceptibility to SCC or IGSCC.

The procedures associated with this AMP provide parameters to be monitored or inspected except for steam generator divider plates, channel heads, and tubesheets. For these latter components, visual inspections are performed at least every 48 effective full power months or every other RFO, whichever results in more frequent inspections for Unit 1 steam generators, and every 72 effective full power months or every third RFO, whichever results in more frequent inspections for Unit 2 steam generators. These inspections of the steam generator head interior surfaces, including the divider plate, are intended to identify signs that cracking, or loss of material may be occurring (e.g., through identification of rust stains).

Inspections of the divider plate may be required for the SPEO. Nickel-alloy divider plates could experience PWSCC as described in the SRP-SLR. The analysis performed by the industry in EPRI TR 3002002850 (Reference 1.6.64) is applicable as PBN Unit 1 steam generators which have alloy-600 divider plates. The industry analyses are currently being evaluated to determine whether they are bounding for PBN and will be completed prior to the SPEO. If the evaluation is not bounding, PBN will perform a one-time inspection of the divider plates to confirm the effectiveness of the actions currently in place to manage SCC (Water Chemistry AMP and the visual inspections performed for the existing Steam Generator AMP). Under the current practice, the divider plate assemblies are visually inspected during every primary-side inspection.

The goal of the inspections associated with this AMP is to ensure that the in-scope components continue to function consistent with the design and CLB of the facility (including regulatory safety margins). These inspections, based on the PBN TS, are performance based, and the actual scope of the inspection and the expansion of sample inspections are justified based on the results of the inspections. If degradation or evidence of degradation is detected, then more detailed inspections or evaluations are to be performed. The AMP procedures reflect these requirements and outline the inspection program to detect degradation of tubes, plugs, and secondary side internals and provide the inspection frequencies. The inspections and monitoring are performed by qualified personnel using qualified techniques in accordance with approved PBN procedures. The PBN primary-to-secondary leakage monitoring program also provides a potential indicator of a loss of steam generator tube integrity.

Condition monitoring assessments are performed to determine whether the structural and accident-induced leakage performance criteria were satisfied during the prior operating interval. Operational assessments are performed to verify that structural and leakage integrity will be maintained for the planned operating interval before the next inspection. If tube integrity cannot be maintained for the planned operating interval before the next inspection, corrective actions are taken in accordance with the PBN CAP. Comparisons of the results of the condition monitoring assessment to the predictions of the previous operational assessment are performed to evaluate the adequacy of the previous operational assessment methodology. If the operational assessment was not conservative in terms of the number and/or severity of the condition, corrective actions are taken in accordance with the SG Integrity Assessment Guidelines. Assessment of tube integrity and plugging or repair criteria of flawed tubes is in accordance with the PBN TS.

Degraded plugs, divider plates, channel heads (interior surfaces), tubesheets (primary side), and secondary side internals are evaluated for continued acceptability on a case-by-case basis. The intent of all evaluations is to ensure that the components will continue to perform their functions consistent with the design and licensing basis of the facility and will not affect the integrity of other components (e.g., by generating loose parts). In addition, when degradation of the steam generator tubes is identified, the TS specified actions are followed. For degradation of other components, the appropriate corrective action is evaluated per NEI 97-06 and the associated EPRI guidelines, the ASME Code Section XI, 10 CFR 50.65, and 10 CFR Part 50, Appendix B, as appropriate.

Procedures implement the performance criteria for tube integrity, condition monitoring requirements, inspection scope and frequency, acceptance criteria for the plugging or repair of flawed tubes, acceptable tube repair methods, leakage monitoring requirements, and operational leakage and accident-induced leakage requirements from the TS.

SG tubes not meeting the TS limits for continued operation are removed from service by installation of tube plugs. This plug installation redefines the reactor coolant pressure boundary and loss of steam generator tube plug integrity can impact the ability of the steam generators to perform its intended function if permitted to continue without corrective action. Tube plugs installed are fabricated from heat treated Inconel Alloy 690 material. Although these plugs have a high resistance to primary water stress corrosion cracking (PWSCC), they are routinely inspected.

Aging is managed through assessment of potential degradation mechanisms, inspections, tube integrity assessments, plugging and repairs, primary-to-secondary leakage monitoring, maintenance of secondary-side component integrity, primary-side and secondary-side water chemistry, and foreign material exclusion.

Volumetric inspections are performed to identify degradations of steam generator tubes such as primary water stress corrosion cracking (PWSCC), outer diameter stress corrosion cracking (ODSCC), and loss of material due to foreign objects and tube support structures. Visual inspections are performed on other primary-side and secondary-side components. The visual inspections of the primary-side components listed above are performed in accordance with the Degradation Assessment (DA) that is prepared as each steam generator is scheduled for examination.

The PBN Steam Generators AMP includes a DA in accordance with the requirements defined in the EPRI Steam Generator Integrity Assessment Guidelines; a DA is performed to determine the type and location of flaws to which the tube may be susceptible, and implementation of inspection methods capable of detecting those forms of degradation are addressed. The DA includes a review of applicable industry operating experience (OE), as well as plant-specific OE which has occurred since the previous DA was performed.

A condition monitoring assessment is performed at the conclusion of each inspection to determine whether inspection criteria is met. A forward-looking evaluation, operational assessment is used to predict that the structural integrity and accident leakage performance will be acceptable during the operating interval until the next inservice inspection.

NUREG-2191 Consistency

The PBN Steam Generators AMP, with enhancement, will be consistent with exception with the ten elements of NUREG-2191, Section XI.M19, “Steam Generators.”

Exceptions to NUREG-2191

The tube-to-tubesheet welds of the PBN Unit 1 steam generators are exempt from inspection and monitoring per the NRC safety evaluation report for permanent Alternate Repair Criteria (H*) for steam generator tubes (Reference ML17159A778).

Enhancements

The PBN Steam Generators AMP will be enhanced as follows for alignment with NUREG-2191. Enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	If the Unit 1 steam generator divider plate assemblies are not bounded by industry analyses EPRI 3002002850, perform one-time inspections of the Unit 1 steam generator divider plate assemblies prior to the SPEO.

Operating Experience

Industry Operating Experience

- Industry operating experiences suggest that primary water stress corrosion cracking (PWSCC) at U-bends, top of the tube sheet locations and locations within the tubesheet are potential degradation mechanisms for thermally treated Alloy 600 (A600TT). End-to-end bobbin inspections were performed on all accessible tubes in the PBN Unit 1 Steam Generators A and B during the refueling outage in 2016. In 2019, rotating +POINT™ probe inspections were performed. Additional eddy current techniques including rotating +POINT™ probes, were used to further investigate bobbin indications and other suspected regions. The results showed no tubes had any reportable crack-like indications.

- Industry operating experiences suggest that outer diameter stress corrosion cracking (ODSCC) is another potential degradation mechanism for A600TT tubing. In 2004, Westinghouse performed an analysis to determine and rank high stress tubes, tubes more susceptible to ODSCC at Point Beach Unit 1. During the Spring 2019 refueling outage, a 75 percent sample of the high stress tubes were inspected at support locations. This completed 100 percent of the support locations in high stress tubes for the period of 72 effective full power months. Axial ODSCC at tube support plate (TSP) intersections has not been previously reported at PBN Unit 1; this test supplemented the bobbin inspection program to gain additional confidence that no such indications are present.

- In May 2017, Salem Unit 1 experienced low-level primary-to-secondary leakage. This OE demonstrated the impact that foreign material can have on site operations in response to primary to secondary leakage and significant contingency planning on a plant level. The foreign material and subsequent tube leak required unplanned steam generator inspections during an outage where no eddy current was planned.

- The largest single cause of plugging after baseline (pre-service) indications is wear at anti-vibration bar (AVB) locations. The available plant data, for replacement steam generators with A600TT tubes indicate that the tube degradation performance has been very good per the EPRI Steam Generator Degradation Database.

- In October 2015, EPRI issued a Part 21 letter describing a change to the calibration of several eddy current technique specification sheets (ETSS). As a result, recent degradation assessments were performed using the updated value including the Spring 2019 refueling outage for PBN Unit 1.
- For the domestic thermally treated Alloy 690 (A690TT) tubing fleet, the leading degradation mechanism in terms of number of tubes affected and number of tubes plugged is wear at AVB locations, followed by wear at TSP locations and wear from foreign objects.

Plant Specific Operating Experience

Unit 1

- During the 2019 refueling outage for Unit 1, one tube was plugged in the A steam generator (SG) due to a foreign object observed during the 6th tube support plate secondary side inspection. Including this 1 new tube plug, there are a total of 14 tubes plugged at Point Beach Unit 1 after the 2019 refueling outage (6 in SG A and 8 in SG B). The effective tube plugging in SG A is now 0.19 percent and in SG B is 0.25 percent. The total tube plugging between both SGs is 0.22 percent.
- A 100 percent visual inspection of tube plugs in both SGs in Unit 1 was performed from the primary side in 2019. There were no visual anomaly conditions, such as a degraded tube plug or abnormal amounts of surrounding boron deposits, reported during performance of the tube plug visual inspections.
- Wear related to tube interaction with AVB supports results from flow-induced vibration in the upper bundle. This mechanical process is related to the tightness of the upper bundle assembly as expressed in the distribution of tube-to-AVB gaps. In general, at plants with similar support structures, AVB wear indications are slow to progress and do not represent a challenge to structural or leakage integrity standards between inspections but may require plugging should observed indication depths exceed the TS plugging criterion of 40 percent through-wall. The most recent inspection performed on A600TT tubes (i.e. PBN Unit 1 2019 refueling outage) concluded that the wear depths of all AVB indications were below the condition monitoring limit, and the projected wear depths at the end of the next cycle are expected to remain well below the condition monitoring limit, and therefore, the performance criteria will be satisfied for AVB wear until the next refueling outage.
- In 2019, a visual inspection of the SG channel head was performed for both SGs in Unit 1. Visual inspections of the SG hot leg and cold leg divider plate and drain line areas, inclusive of the entire divider plate to channel head weld and all visible clad surfaces, were performed. Satisfactory results were observed in both SGs. The areas where rust discoloration had been observed in 2007 (locations where cladding was missing near the hot leg primary manway) were examined again in 2019, but the rust discoloration was no longer apparent. An evaluation was performed that estimated a maximum corrosion depth of only 0.095 inch by October 2030 for this cladding breach;

observations of the cladding breach in 2019 did not indicate excessive corrosion products that might suggest a greater corrosion depth.

- In 2019, an inspection was performed to identify any foreign objects and foreign object wear. Sludge lancing removed deposit quantities consistent with previous sludge lancing operations and provided an acceptable cleanliness condition. A total of 35 foreign objects were visually identified at the top of the tubesheet, all of which were either removed or evaluated as acceptable. Two foreign objects were identified at the 6th tube support plate that could not be retrieved. Additional +POINT™ probe inspections were performed in SG A to identify any wear that might have occurred on tubes adjacent to the foreign object that was found at the 6th support plate. The foreign material could not be accessed to be retrieved. Therefore, it was decided to plug the affected tube in order to prevent any potential degradation that could affect tube structural or leakage integrity.

Unit 2

- As of the 2017 refueling outage, Unit 2 has no tubes plugged in SG 2A and 4 tubes plugged in SG 2B, which constitutes a total plugging level of 0.057

- All four were plugged as a precautionary measure, 2 as a result of shallow (approximately 10% through wall) wear type volumetric indications at the top of the tube sheet, and 2 as a result of excessive tube noise in the eddy current signal. No tubes have been plugged because of corrosion type degradation, which is consistent with the experience of other SG's with thermally treated Alloy 690 tubes. The inspection detected minor AVB wear and tube wear at broached supports in SG 2A.

- Tube wear at TSPs at PBN Unit 2 was first reported during the 2005 refueling outage at one location in SG 2A. The +POINT™ probe inspection determined that there were wear indications present at 2 of the broach land contacts. During the inspection in 2014, TSP wear was reported at three locations in two tubes in SG 2A and one location in one tube in SG 2B. The results determined the tubes were acceptable and all were left in service.

- In 2017, a visual inspection of the SG channel head was performed for both SGs in Unit 2. No corrosion-related degradation was identified.

The effectiveness of the PBN Steam Generators AMP was demonstrated as a result of the October 2010 and March 2013 NRC Phase 2 post-approval site inspections which were conducted prior to entering into the original PEO for each unit. The inspectors reviewed the licensing basis, program basis document, implementing procedures, and completed inspections; and interviewed the PBN plant personnel responsible for this program. The inspectors verified that program and associated enhancements were in place. Based on review of the timeliness and adequacy of PBN's actions, the inspectors determined PBN had met the required commitments for the PBN Steam Generators AMP.

In 2018, an effectiveness review of the PBN Steam Generators AMP was performed following the guidelines provided in NEI 14-12. The effectiveness review covered the applicable ten program elements with focuses on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). In response to the AMP effectiveness review, the PBN Steam Generator AMP Basis Document was updated to include the new revision of EPRI guidelines, NSAC-202L-R4, and to update FAC procedures. PBN Steam Generators AMP was determined to continue to be effectively implemented, and there were no gaps identified for this program.

In 2019, the NRC performed the IP 71003 Phase 4 inspections at PBN Units 1 and 2. The team selected seven AMPs including the PBN Steam Generators AMP for evaluation considering risk insights and programs that were enhanced or new under the renewed operating license. The elements evaluated were scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. No findings were identified for the PBN Steam Generators AMP.

The PBN Steam Generators health reports from January 2015 through February 2020 were evaluated as part of the SLRA OE review. From the first quarter of 2015 through the first quarter of 2019, the program health was “green.” From the second quarter of 2019 to the fourth quarter of 2019, the program health was “white”. This was mainly due to the conservative scoring method. As of the first quarter of 2020, the program health was “green.”

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Steam Generators AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Steam Generators AMP, with the exception and enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.11 Open-Cycle Cooling Water System

Program Description

The PBN Open-Cycle Cooling Water System AMP is an existing AMP, previously known as the Open Cycle Cooling (Service) Water System Surveillance Program, that manages the effects of aging on internal piping component surfaces exposed to a raw water environment from the service water system. The PBN OCCW System AMP applies to components constructed of various materials including steel (e.g., carbon/low alloy steel and cast iron), stainless steel (SS; including cast austenitic SS), copper alloys, and polymeric materials (i.e., neoprene expansion joints).

This objective is accomplished, in part, through implementing portions of the recommendations for the NRC Generic Letter (GL) 89-13. NRC GL 89-13 defines the open-cycle cooling water system as a system or systems that transfer heat from safety-related systems, structures, and components (SSCs) to the ultimate heat sink (i.e., the PBN service water system). The PBN Open-Cycle Cooling Water System AMP includes: (a) surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of heat exchangers, (c) routine inspection and maintenance so that corrosion, erosion, protective coating failure, fouling, and biofouling cannot degrade the performance of systems serviced by the SW system. Inspection and examination methods include visual, ultrasonic (UT), eddy current (ECT), and radiography as appropriate. This AMP includes enhancements to the guidance in NRC GL 89-13 that address operating experience (OE) such that aging effects are adequately managed.

Biofouling control is accomplished by the addition of oxidizing biocide to the systems that are exposed to Lake Michigan water, periodic mechanical removal of mussels, and chemical treatment for mussel control. The primary method for microfouling control is operation of the chlorination system. The concentration of the biocide is adjusted based on evaluations of microfouling evidence. Continuous biocide injection is the primary method used to control mussels in the service water system.

The preferred method of cleaning heat exchanger tubes is hydrolancing and the NDE method most used is ECT. The inspections are used to track the condition of the equipment exposed to raw water and the effectiveness of the biofouling control methods. In addition, the ECT results are used to predict the remaining life of the tubes so that proper steps can be taken to ensure that heat exchangers will continue to perform their intended functions. The PBN GL 89-13 Program commitments include the performance testing of selected heat exchangers. In-scope components within the service water system that are not frequently operated are periodically flushed to control sediment build-up, preferably during the biocide treatments, whenever possible.

The PBN Open-Cycle Cooling Water System AMP is required to monitor the aging effects of loss of material, reduction of heat transfer, flow blockage, and cracking where applicable. The parameters monitored, inspected, or tested vary depending on the component and are based on operating experience.

Some heat exchangers are visually inspected and some are tested for flow obstruction, loss of heat transfer capability, and tube wall thickness deficiencies (via

ECT or UT). Pressure drop across certain components are measured and trended, while some components are periodically cleaned and inspected, and a Service Water System Performance Monitoring Trend Plan is maintained and utilized per procedure.

PBN does not currently have any concrete piping components exposed to raw water from the service water system, therefore, the management of concrete piping in accordance with American Concrete Institute (ACI) 349.3R and ACI 201.R1 is not applicable. Likewise, loss of coating integrity is managed by the PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP.

Inspection scope, methods, and frequencies are in accordance with the PBN GL 89-13 Program. The PBN GL 89-13 Program states that testing frequencies are determined after three tests to provide assurance that equipment will perform the intended function between test intervals and the maximum test interval does not exceed 5 years. The frequency and scope of inspections vary with the component location, system flow rate, past history, and calculated life remaining based on the guidelines in the Service Water In-Service Inspection Program and the Heat Exchanger Condition Assessment Program.

The PBN Open-Cycle Cooling Water System AMP performs visual inspections to identify fouling and provide a qualitative assessment for loss of material due to various forms of corrosion and erosion. Volumetric examinations, such as UT, eddy current testing, and radiography are used to quantify the extent of wall thinning or loss of material. Inspector qualifications are defined by the respective procedures and program documents and inspections and tests are performed by personnel qualified in accordance with those documents.

Heat transfer testing results are documented in plant procedures and are trended and reviewed by the appropriate engineering group. For heat exchangers that are tested for heat transfer capability or flow blockage, test results are trended to verify adequacy of testing frequencies. Likewise, for heat exchangers that are inspected for degradation in lieu of testing, inspection results are trended to evaluate adequacy of inspection frequencies. This trending is captured by the Service Water System Performance Monitoring Trend Plan.

If fouling is identified, an operability determination evaluation of the fouled heat exchanger is performed to confirm that the system maintains its required heat transfer capability. Evidence of corrosion is evaluated for its potential impact on the integrity of the piping, and component degradation such as pipe wall thinning and silt build-up, is measured and recorded to predict the expected remaining life of the component such that corrective actions can be taken prior to a loss of intended function as described in the Service Water In-Service Inspection and respective surveillance procedures. For ongoing degradation due to specific aging mechanisms (e.g., microbiologically-influenced corrosion (MIC)), the PBN Open-Cycle Cooling Water System AMP includes trending of wall thickness measurements at susceptible locations to adjust the monitoring frequency and the number of inspection locations. The methodology for the frequency of examinations, locations of examinations, analysis of inspection or test results, and acceptance criteria are specified in the applicable procedures. Therefore, inspections and non-destructive testing will determine the extent of MIC and biofouling, the condition of any surface coating, the extent of corrosion, and amount of blockage due to silting.

The general acceptance criteria associated with the PBN Open-Cycle Cooling Water System AMP are specified in the procedures that control the inspections and testing of components. Acceptance criteria are based on maintaining the system free of significant sediment build-up and able to perform its intended functions as demonstrated by flow and performance testing. The PBN GL 89-13 Program and the Service Water System Performance Monitoring Trend Plan contain details of applicable performance and flow testing. When wall thickness is measured, the measured thickness is not allowed to be less than the construction code required minimum wall thickness, otherwise corrective action is required. Likewise, if the wall thickness is predicted to be less than the minimum wall thickness at the next scheduled inspection, then corrective action is required. For heat exchangers that are tested by performing a heat balance (heat exchanger performance) test, the heat removal capability (or respective heat exchanger temperature) is required to remain within the design values. For ongoing degradation mechanisms, the PBN Open-Cycle Cooling Water System AMP performs an operability evaluation that uses criteria from the relevant ASME Code (e.g. Code Case N-513 for moderate energy Class 2 and 3 piping). Results of the evaluation reveal the extent or rate of degradation and prompt more comprehensive corrective actions as needed.

When measured wall thickness or the wall thickness predicted for the next scheduled examination is less than the design minimum wall thickness, the PBN Open-Cycle Cooling Water System AMP reports the deficiency with an Action Request (AR), then an operability or functionality assessment is performed and repair or replacement is performed as needed per the evaluation. When piping is replaced prior to failure due to concerns with wall thinning or flow blockage, additional inspections are considered on similar areas of the system to determine the presence and extent of degradation.

NUREG-2191 Consistency

The PBN Open-Cycle Cooling Water System AMP, with enhancements, will be consistent with exception with the 10 elements of NUREG-2191, Section XI.M20, “Open-Cycle Cooling Water System.”

Exceptions to NUREG-2191

The PBN Open-Cycle Cooling Water System AMP will take the following exception to the NUREG-2191 guidance:

- Not all of the safety related heat exchangers are tested to verify heat transfer capability by performing a heat balance (heat exchanger performance) test. The primary auxiliary building battery room vent coolers, turbine driven auxiliary feedwater pump turbine oil coolers, containment fan motor coolers, and emergency diesel generator coolant heat exchangers are not routinely tested to verify heat transfer capability. As described in the PBN GL 89-13 Program Document, an acceptable alternative to testing that can be applied to small heat exchangers is frequent regular maintenance. These components are periodically flushed and/or cleaned and inspected as described in the PBN GL 89-13 program document and/or the heat exchanger condition assessment program. The “D” containment accident fan heat exchangers in each unit are periodically performance tested and are considered to be representative of the other containment accident fan heat exchangers.

Enhancements

The PBN Open-Cycle Cooling System AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be completed no later than six months prior to entering the SPEO or no later than the last refueling outage prior to the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Update the primary program documents and procedures and applicable preventive maintenance requirements to clearly identify the portions of the service water system, within the scope of GL 89-13, where flow monitoring is not performed. For these portions of the service water system, the procedures will calculate friction (or roughness) factors based on test results from the flow monitored portions of the service water system and use these factors to confirm that design flow rates will be achieved with the overall fouling identified in the system.
4. Detection of Aging Effects	Update the primary program documents and procedures and applicable preventive maintenance requirements to clearly identify the inspections and tests that are within the scope of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) and those inspections and tests that are not. The procedures and preventive maintenance requirements that perform the ASME Code inspections and tests shall be consistent with and reference the respective ASME Code. The procedures and preventive maintenance requirements that perform the Non-ASME Code inspections and tests shall follow site procedures that include requirements for items such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes.
4. Detection of Aging Effects	Update the primary program documents and procedures and applicable preventive maintenance requirements to state that examinations of polymeric materials (i.e., neoprene expansion joints) shall include visual and tactile inspections whenever the component surfaces are accessible during the performance of periodic surveillances or during maintenance activities or scheduled outages. These inspections shall check for surface cracking, crazing, discoloration, scuffing, loss of material due to wear, dimensional change, and exposure of reinforcing fibers/mesh/metal. Manual or, physical manipulation or pressurization of flexible polymeric components is used to augment visual inspection, where appropriate, to assess loss of material or strength. The sample size for manipulation is at least 10 percent of accessible surface area, including visually identified suspect areas. Hardening, loss of strength, or loss of material due to wear is expected to be detectable before any loss of intended function.

Element Affected	Enhancement
5. Monitoring and Trending	Update the primary program documents and procedures and applicable preventive maintenance requirements to perform trending of the observed or calculated friction (or roughness) factors to confirm that the design flow rates will be achieved in the portions of the service water system, within the scope of GL 89-13, where flow monitoring is not performed.
6. Acceptance Criteria	Update the primary program documents and procedures and applicable preventive maintenance requirements to clarify that when previous pipe wall thickness measurements are not available for the determination of a corrosion rate, a corrosion rate that has been calculated from other locations with nearly identical operating conditions, material, pipe size, and configuration may be used to determine re-inspection intervals. This corrosion rate assignment must be documented in an Engineering Evaluation to document the location(s) used, basis for correlation, and final corrosion rate assigned. A mill tolerance of 12.5 percent shall be used for added conservatism when establishing an initial wall thickness value when determining corrosion rates at new inspection locations if corrosion rates at other locations with nearly identical operating conditions, material, pipe size, and configuration cannot be used.
7. Corrective Actions	Update the primary program documents and procedures and applicable preventive maintenance requirements to clarify that if fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage, loss of material, and chemical treatment effectiveness. For ongoing degradation mechanisms (e.g., MIC and erosion) or recurring loss of material due to internal corrosion, the frequency and extent of wall thickness inspections are increased commensurate with the significance of the degradation. The number of increased inspections is determined in accordance with the PBN corrective action program; however, no fewer than five additional inspections are conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. Since PBN is a two-unit site, the additional inspections include inspections of components with the same material, environment, and aging effect combination at the opposite unit. The additional inspections will occur at least every 24 months until the rate of recurring internal corrosion occurrences no longer meets the criteria for "loss of material due to recurring internal corrosion" as defined in NUREG-2192. The selected inspection locations will be periodically reviewed to validate their relevance and usefulness and adjusted as appropriate. Evaluation of the inspection results will include (1) a comparison to the nominal wall thickness or previous wall thickness measurements to determine rate of corrosion degradation; (2) a comparison to the design minimum allowable wall thickness to determine the acceptability of the component for continued use; and (3) a determination of reinspection interval.

Operating Experience

Industry Operating Experience

The list below provides industry OE relevant to the PBN OCCW System AMP, as described in NUREG-2191, Section XI.M20:

- Loss of material due to corrosion (including MIC and erosion): IN 85-30, IN 2007-06, LER 247/2001-006, LER 306/2004-001, LER 483/2005-002, LER 331/2006-003, LER 255/2007-002, LER 454/2007-002, LER 254/2011-001, LER 255/2013-001, LER 286/2014-002
- Protective coating failure leading to unanticipated corrosion: IN 85-24, IN 2007-06, LER 286/2002-001, LER 286/2011-003
- Reduction of heat transfer and flow blockage due to fouling within piping and heat exchangers due to protective coating failures and accumulations of silt/sediment: IN 81-21, IN 86-96, IN 2004-07, IN 2006-17, IN 2007-28, IN 2008-11, LER 413/1999-010, LER 305/2000-007, LER 266/2002-003, LER 413/2003-004, LER 263/2007-004, LER 321/2010-002, LER 457/2011-001, LER 457/2011-002 ,LER 397/2013-002
- Cracking due to stress corrosion in brass tubing: LER 305/2002-002
- Pitting in stainless steel: LER 247/2013-004

Plant Specific Operating Experience

Between 2010 and 2020, there were a number of action requests (ARs) initiated to evaluate and/or correct degradation associated with components exposed to raw water from the service water system.

- In January 2010, an inspection of the tubesheets and covers of the primary auxiliary building battery room vent cooler revealed worse degradation than expected. Pitting on the lower coil return tubesheet was approximately 3/32 inches using a straightedge and rough measuring the depth; and the corrosion allowance is 1/8 inch. The worst pitting locations had active pitting as the pits were shiny carbon steel after breaking off the tubercles. Most pit locations were old and rusty - even after breaking off new tubercle growth. Pitting was expected to be no more than 1/16 inch based on the last years inspections. Replacement coils were installed in March 2010.

- In May 2010, inspection of the nonsafety-related strainer backwash outlet valve and attached piping indicated that cavitation pitting had occurred in the valve body and caused a pinhole leak. The attached upstream and downstream piping were essentially undamaged. The cavitation occurred due to the high pressure drop across the valve which connects to a 6-inch drainpipe that discharges to the screen wash trench. As a result, five inspections for cavitation pitting were added to the service water system inservice inspection scope to be performed with radiography.

- In July 2010, a service water solenoid valve was removed from service and destructively tested as part of license renewal one-time inspections for selective leaching. The body and bonnet of the solenoid valve were verified to be brass with a nominal composition of 40 weight percent zinc. Since the zinc content exceeded 15 percent by weight, this valve was considered potentially susceptible to selective leaching in the form of dezincification. The presence of dezincification was verified by cross-sectioning and sand blasting the wetted surfaces of the valve body and bonnet. Metallographic examination of selected areas revealed maximum dezincification depth measuring 0.020 inches (valve body) and 0.011 inches (valve bonnet). As a result, the valve was replaced and work requests were initiated to identify additional valves with high (>15 percent zinc) for further sampling and testing.

- In August 2010, a GL 89-13 inspection of a diesel cooler indicated the start of fouling in the tubes and increased fouling on the tubesheets. This fouling was documented as a new aging mechanism for the diesel coolers. For the first time in several years the tubes were not obviously shiny clean (especially the 3rd and 4th pass). The 3rd pass outlet through 4th pass outlet felt slightly slippery which would indicate biofilm growth. The tubesheet and channel areas which are not part of the heat transfer area had been developing staining over the years, which was a bacteria process and normal for service water heat exchangers, as these are low or no flow areas. The tubesheet areas of the 1st and 3rd pass outlets have now developed a thin layer of some thickness (easily disturbed by finger pressure); which was slippery - indicating biofilm. Samples were taken for biological analysis. There was no operability concern as any observed tube fouling would be within the design fouling factor for the heat exchanger. In addition, there was only one obstructed tube (mussel shell), no tubes blocked by fouling, and no tubes permanently plugged. The tubes and tubesheet were cleaned.

- In January 2011, the coatings on the tubesheet, channel, covers, and gasket sealing surfaces of inlet and outlet ends of the common “B” component cooling water (CCW) heat exchanger were inspected. Several small blisters and pits were noted on the inlet cover surface, and on the inlet and outlet channel gasket sealing surfaces. On the inlet cover surface, there were six coating blisters, each with pits in the steel that varied in size from about 1/4-inch to 1-inch diameter, and from 1/16 to 3/16-inch depth. The pits each appeared to be filled with black MIC bacteria. On the inlet channel gasket surface, seven small pits were found in random locations around the circumference, each approximately 1/4-inch to 1/2-inch in diameter and 1/16-inch to 1/8-inch depth. These small pits were filled with red rust and/or black MIC material. On the outlet channel gasket surface, three small pits were found. These were relatively small, only about 1/4-inch diameter or less, and from 1/16- to 1/8-inch depth. These were likewise filled with red rust and black MIC material. The surfaces were cleaned and recoated.

- In April 2011, a high definition automated UT scan of the carbon steel shells of the common “A” and “B” spent fuel pool heat exchangers indicated significant under-deposit pitting that was likely to reach code min-wall in about 5 years (i.e., 2016). The nominal shell thickness was 1/2 inch and the ASME Code Minimum Wall was 0.147 inch. The inspection results were as follows for the worst detected pit: 0.216 inch at the “A” heat exchanger and 0.227 inch at the “B” heat exchanger. These were the lead pits, with multiple pits of lesser degradation identified. Also, the scans covered just over 70 percent of the shell area (nozzle and support interferences of the automated equipment) so additional pits in the non-inspected areas likely existed. As a corrective action, a modification was added to the long-term asset management (LTAM) to replace the coolers.

- In May 2011, some slight inside surface pitting and corrosion was noted during an inspection of service water piping prior to installing a valve. The corrosion had the appearance and indication of possible MIC. The corrosion was determined to be minor in nature and the installation of the valve proceeded. The condition reported was typical for most of the service water system, which is of carbon steel construction.

- In August 2011, a pinhole leak was identified approximately 6 inches downstream of the Unit 1 “A” CCW heat exchanger outlet waterbox blowdown valve. Based on the pinhole leak being downstream of an outlet blowdown valve to the service water return header, localized cavitation pitting was the most likely cause. The leaking pipe was replaced and a post maintenance leak check was completed satisfactorily. A work order to replace the respective piping on the other blowdown lines was completed in May 2014.

- In October 2011, sections of 2-inch diameter service water piping located downstream of the CCW heat exchanger outlet blowdown valves were suspected to have cavitation damage, since cavitation pitting was found in piping being replaced downstream of the Unit 1 “A” CCW heat exchanger as noted above. These piping sections are all connected to the common CCW heat exchanger service water blowdown header. This piping is nonsafety-related and non-ASME Section XI. As a proactive measure, the pitted piping was replaced.

- In November 2011, non-destructive examinations noted degradation due to MIC on the service water system side of the common “A” cable spreading room air conditioning unit. Although the cable spreading room air conditioning unit is not listed in the GL 89-13 Program scope, this OE is relevant to the service water system and, likewise, the PBN Open-Cycle Cooling Water AMP. Areas that were cleaned showed corrosion and loss of material. The adjacent pipe was examined, and heavy deposits/tubercles were found. Multiple locations on the outlet tube sheet were noted to be below 0.750 inches. An area at the approximate center of the outlet tube sheet showed wall loss of approximately 0.350 inches, which resulted in a nonconformance with the design minimum wall thickness. The heat exchangers were replaced in October 2012.

- In February 2013, the coatings on the covers and gasket sealing surfaces of inlet and outlet ends of the Unit 2 “D” CCW heat exchanger were inspected. On the inlet gasket surface, one blister and a small pit of about 3/16-inch depth as well as three areas of blistered or missing coatings that did not exhibit pitting beneath the blisters were found. On the inlet cover, one blister and small pit of about 3/16-inch depth were found. On the outlet gasket surface, found four blistered and delaminated areas were found. All of these blisters and delaminations were within areas recently repaired in the previous two cycles. Beneath these blisters and delaminations, the steel was observed to be shiny and smooth, without the surface profile/roughness to ensure adequate adhesion. On the outlet cover, two blisters, also within areas recently repaired in the past two cycles were found. The blisters and pits were each filled with water and black MIC material, which was removed to expose bare shiny steel in order to confirm the depth of the pits. The surfaces were cleaned and the coatings repaired.

- In March 2013, during service water system piping interference removal activities, the material condition of some 1-inch was noted to be unsatisfactory. The amount of rust and internal corrosion in the piping was such that the piping failed when removing the couplings. A detailed walkdown was performed on the 1-inch piping and indicated that approximately 30 to 35 feet of piping was affected. The piping was replaced in August 2013.

- In July 2014, a service water system valve body was identified with a pin hole leak. The subject valve was replaced with a stainless steel valve.

- In April 2015, during disassembly of a check valve, the disc was found wedged in the valve body keeping the check valve in the open position. The check valve internals and body were determined to be worn due to general corrosion. Immediate maintenance repairs were performed to ensure that the disc would not get stuck in the body.

- In April 2015, a review of the data reports from a 2014 phased array UT scan of the shell of the spent fuel pool heat exchangers and a comparison to the 2011 inspection indicated an increase in both quantity and depth of under deposit and MIC pitting on the shells since 2011. Based on the 2011 data shell minimum wall (end of life) was estimated at 2016; and the spent fuel pool coolers were margin ranked “White” for margin management at the time. The 2011 inspection of the common “A” spent fuel pool heat exchanger identified 46 areas below 0.350 inch and the respective 2014 inspection identified 157 areas below 0.350 inch. The 2011 inspection of the common “B” spent fuel pool heat exchanger identified 54 areas below 0.350 inch and the respective 2014 inspection identified 78 areas below 0.350 inch. The nominal shell thickness was 1/2 inch and the ASME Code Minimum Wall was 0.147 inch for the cylindrical shell (excluding heads). Weld repairs were performed in July 2015.

- In March 2018, a nonsafety-related air conditioning unit outlet temperature control valve had a pinhole leak in the casting of the body. The valve was replaced.

- In May 2018, as part of an extent of condition assessment under the service water inservice inspection program due to a pinhole (through wall) leak at the upstream weld of a valve, inspections were performed on the piping upstream. Some substantial localized pitting was identified and the piping and valve were replaced.

To assess effectiveness of AMPs credited for subsequent license renewal, the AMPs are reviewed against the criteria provided in NEI 14-12. The most recent effectiveness review of Aging Management Programs at PBN was performed in 2018. The effectiveness review covered the applicable ten program elements with particular attention on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). Full AMP effectiveness reviews are performed at least every five years.

The use of AMP effectiveness self-assessments and the relatively high number of AMP revisions shows that the PBN Open-Cycle Cooling Water System AMP is regularly updated, which is a trait of a healthy AMP.

Quarterly health reports for the service water system are reported. The quarterly service water system health reports from January 2015 through February 2020 were evaluated as part of the SLRA OE review. The service water system health reports are typically green and the general trend for the service water system health report scoring has been positive.

In 2010, 2012 and 2013 the NRC performed the 71003 Phase 1 and 2 inspections for PBN Units 1 and 2. The inspectors verified that the program and program enhancements were in place to ensure: (1) surveillance and control of biofouling; (2) periodic and one-time surveillance testing and inspections to evaluate system and component performance; (3) inspection methods include heat transfer testing, visual testing, ultrasonic testing, and eddy current testing; and (4) routine inspection and Maintenance Program activities to ensure that aging effects do not impair component intended function. The inspectors verified the testing and maintenance activities appropriately implemented the actions. Based on review of the timeliness and adequacy of PBN's actions, the inspectors determined that PBN had met the commitments related to the PBN Open-Cycle Cooling Water System AMP.

In 2019, the NRC performed the 71003 Phase 4 inspections at PBN Units 1 and 2. The PBN Open-Cycle Cooling (Service) Water System Surveillance Program was one of the seven AMPs selected for review. No findings were identified.

Although, there are a number of action requests associated with the PBN service water system, the vast majority of these are relatively minor (e.g., wall thickness being below 87.5 percent but above minimum wall thickness, or minor coating repair) and are frequently identified through the service water inservice inspection program. Likewise, opportunistic inspections have been effectively utilized to identify internal wall thinning, fouling, and flow blockage prior to any significant component failure occurring. Finally, PBN has effectively utilized extent-of-condition evaluations to identify issues in the service water system, and no major service water system piping component failures occurred between 2010 and 2020. Therefore, no enhancements are required with respect to the OE.

The PBN OCCW System AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B. The above OE provides objective evidence that the PBN Open-Cycle Cooling Water System AMP activities are effective in identifying and managing the aging effects (loss of material, cracking, flow blockage, and low of heat transfer) within the piping, piping components, piping elements, and heat exchanger components exposed to raw water within or provided by the service water system. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found, and adequate corrective actions were taken to prevent recurrence. Therefore, there is objective evidence that continued implementation of the AMP, with the identified exception and enhancements, will effectively identify and address degradation prior to component loss of intended function. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Open-Cycle Cooling System AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Open-Cycle Cooling System AMP, with the exception and enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.12 Closed Treated Water Systems

Program Description

The PBN Closed Treated Water Systems AMP, previously known as the Closed-Cycle Cooling Water System Surveillance Program, is an existing AMP that manages aging of the internal surfaces of piping, piping components, piping elements, and heat exchanger components exposed to a closed treated water environment during the SPEO. The AMP manages the aging effects of loss of material due to corrosion, cracking due to SCC, and reduction of heat transfer due to fouling. The program scope includes the component cooling water system, emergency diesel generator (EDG) coolant systems, gas turbine generator (G-05) and associated diesels (G-500 and G-501) coolant systems, the chilled water loop for the control room and computer room ventilation systems, and the chilled water loop for the cable spreading room ventilation system.

The PBN Closed Treated Water Systems AMP is a mitigation program that also includes condition monitoring to verify the effectiveness of the mitigation activities. The AMP includes: (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized; (b) chemical testing of the water to demonstrate that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation. Chromate based inhibitors are used for the component cooling water system, and ethylene glycol-based coolant is used for the EDG coolant systems, gas turbine generator and associated diesels coolant systems, and the ventilation chilled water systems.

To prevent loss of material and cracking due to corrosion and stress corrosion cracking, the PBN Closed Treated Water Systems AMP periodically monitors the closed cooling system chemistry to verify it is being maintained within specified limits. The parameters monitored in the closed cooling systems include pH, chloride, fluoride, chromate, sulfate, iron, and copper concentrations, conductivity, radioactivity (isotopic activity), total suspended solids (sediment weight percentage), calcium, and magnesium as appropriate, and the acceptable ranges of values for these parameters and testing frequency are in accordance with EPRI TR-3002000590 (Reference 1.6.65), Table 5-4 and manufacturer recommendations where applicable.

When water chemistry concentrations are not within normal operating ranges, then monitoring frequency is increased, as appropriate, and water chemistry parameters are returned to the normal operating range within the prescribed timeframe for each action level, or an Action Request (AR) is initiated to evaluate and correct the water chemistry. The water sampling procedures provide corrective steps to take if water chemistry is outside of the recommended ranges. Additionally, the water chemistry parameters are trended in a database. For the EDG coolant systems, gas turbine generator and associated diesels coolant systems, and the ventilation chilled water systems, coolant chemistry is sampled and analyzed at an off-site laboratory.

The PBN Closed Treated Water Systems AMP does not perform microbiological testing within the respective systems, since the chromate and ethylene glycol additives are effective as biocides and no site operating experience (OE) related to MIC was identified as applicable for the PBN closed treated water systems. However, testing is performed if MIC is suspected. Likewise, corrosion coupon testing has not previously been used for closed treated water systems and site OE has not identified a need for corrosion coupon testing.

NUREG-2191 Consistency

The PBN Closed Treated Water Systems AMP, with enhancements, will be consistent with an exception with the 10 elements of NUREG-2191, Section XI.M21A, "Closed Treated Water Systems" as modified by SLR-ISG-Mechanical-2020-XX, Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance.

Exceptions to NUREG-2191

The PBN Closed Treated Water Systems AMP includes the following exception to the NUREG-2191 guidance:

PBN replaces the coolant for the cable spreading room chilled water system, the control room and computer room chilled water system, the gas turbine starting diesel generator, and the auxiliary diesel generators on a periodic basis and sends samples to be analyzed at reputable off-site laboratories. EPRI TR-3002000590 Table 5-11 states that other than glycol volume concentration and pH, the parameters just require being within manufacturer recommendations or having the trend evaluated. The sampling procedure states required pH and glycol concentration ranges. These ethylene glycol-based systems are sampled on a quarterly basis, with the exception of the gas turbine coolant system, which is sampled annually. This is consistent with sampling frequency for Tier 1 and Tier 2 systems stated in EPRI TR-3002000590, Table 5-11. Since the current sampling of these coolant systems already focuses on the critical parameters (glycol concentration and pH) and is performed at a frequency consistent with EPRI TR-3002000590, Table 5-11, additional requirements from an EPRI standard are unnecessary.

Enhancements

The PBN Closed Treated Water Systems AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be completed no later than six months prior to entering the SPEO or no later than the last refueling outage prior to the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Ensure that the new visual inspection procedure(s) and/or preventive maintenance requirements evaluate the visual appearance of surfaces for evidence of loss of material.
3. Parameters Monitored or Inspected	Create new procedure(s) and/or preventive maintenance requirements that perform surface and/or volumetric examinations and evaluate the examination results for surface discontinuities indicative of cracking.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Create visual inspection procedure(s) and/or preventive maintenance requirements, for heat exchangers that are unable to be functionally tested, to determine the tube surface cleanliness and verify that design heat removal rates are maintained.
4. Detection of Aging Effects	Ensure that visual inspections of closed treated water system components' internal surfaces are conducted whenever the system boundary is opened. The ongoing opportunistic visual inspections can be credited towards the representative samples for the loss of material and fouling; however, surface or volumetric examinations must be used to confirm that there is no cracking.
4. Detection of Aging Effects	Create new procedure(s) and/or preventive maintenance requirements to ensure that the inspection requirements from NUREG-2191 are met. At a minimum, in each 10-year period during the SPEO, a representative sample of components is inspected using techniques capable of detecting loss of material, cracking, and fouling, as appropriate. The sample population is defined as follows: • 20 percent of the population (defined as components having the same material, water treatment program, and aging effect combination) OR; • A maximum of 19 components per population at each unit, since Point Beach is a two-unit plant.
5. Monitoring and Trending	Ensure that the new inspection and test procedure(s) and/or preventive maintenance requirements will evaluate their respective results against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation. Where practical, identified degradation is projected through the next scheduled inspection.
6. Acceptance Criteria	Ensure that the new inspection and test procedure(s) and/or preventive maintenance requirements identify and evaluate any detectable loss of material, cracking, or fouling per the PBN corrective action program.

Element Affected	Enhancement
7. Corrective Actions	Ensure that the following additional inspections and actions are required if a post-repair/replacement inspection or subsequent inspection fails to meet acceptance criteria: • The number of increased inspections is determined in accordance with the PBN corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. • If subsequent inspections do not meet acceptance criteria, an extent-of-condition and extent-of-cause analysis is conducted to determine the further extent of inspections. • Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. Since Point Beach is a two-unit site, the additional inspections include inspections at all of the units with the same material, environment, and aging effect combination. • The additional inspections are completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.

Operating Experience

Industry Operating Experience

The list below provides aging mechanisms and industry OE relevant to the PBN Closed Treated Water Systems AMP, as described in NUREG-2191, Section XI.M21A:

- Degradation of closed-cycle cooling water (CCCW) systems due to corrosion product buildup: Licensee Event Report (LER) 327/1993-029
- Degradation of CCCW systems due to through-wall cracks in supply lines: LER 280/1991-019
- SCC of stainless steel reactor recirculation pump seal heat exchanger coils (attributed to localized boiling of the CCCW system which concentrated water impurities on coil surfaces): LER 263/2014-001

As EPRI water chemistry guidelines are updated, PBN updates the governing chemistry procedure so that the latest guidelines are being followed. This includes latest recommendations for corrosion inhibitors and biocides added.

Plant Specific Operating Experience

Between 2010 and 2020, the following action requests (ARs) were initiated to evaluate and/or correct degradation associated with components exposed to an environment of closed treated water. Several ARs were initiated for closed treated water system heat exchanger components, but if the condition originated on the raw water (service water) side of the heat exchanger, then those ARs were evaluated in the PBN Open-Cycle Cooling Water System AMP instead.

- In March 2010, an eddy current inspection of the Unit 1 “A” RHR heat exchanger identified significant vibration induced tube degradation (up to 87 percent wall loss). The inspection identified 42 tubes as affected, and many tubes had vibration damage at multiple points (at each baffle and free-span tube to tube fretting). The worst fretting damage occurred in the U-bend section of the heat exchanger. An apparent cause evaluation and an inspection of the “B” RHR heat exchanger were subsequently performed. The inspection of the “B” RHR heat exchanger identified 14 tubes as affected with up to 34 percent wall loss. The possible causes included design deficiencies (inadequate baffle spacing), construction tolerances, operational considerations (high flow rate), eddy current analysis error, and foreign material wear. As a corrective action, a work order plugged and stabilized the impacted tubes in June 2010.

- In March 2011, an eddy current inspection of the Unit 2 “A” RHR heat exchanger identified vibration induced tube degradation up to 20 percent wall loss. While this is below the plugging criteria, the tube with 20 percent wall loss was plugged.

Eddy current testing includes a specific technique that provides information of the gap size at the support plates. The basis is the larger the gap, the more potential for increased vibration. The latest eddy current testing performed in 2017 was considered favorable as the gaps were not getting larger and therefore the vibration should not worsen. PBN continues to monitor and trend tube conditions through preventive maintenance tasks to ensure the component cooling heat exchangers are opened, cleaned (remove corrosion, fouling and scaling material from the inner surface of tubes), and inspected on a 3-year basis. Also eddy current testing per NRC Generic Letter GL 89-13 is performed every 6 years and is focused on erosion (external and internal) and scaling of tubes, tube cracking or other defects, and the condition of the shell-side inlet nozzle.

Trending of nitrite and microbiological levels in the engine coolant of the EDGs revealed slight in-leakage of service water. This resulted in the heat exchangers being inspected and repaired or replaced. In late 2007 the coolant was switched from nitrite based to ethylene glycol-based when new coolers were installed. Ethylene glycol inhibits microbiological growth, and therefore, trending of microbiological levels is no longer necessary.

There have been no other significant degradation issues with the EDG coolant systems, gas turbine and associated diesel coolant systems, or the ventilation chilled water systems. In May 2009 fouling was reported on the ethylene glycol-based solution side of the gas turbine lube oil cooler, when it was opened for routine eddy current inspection. However, no decline in cooler performance had been observed. The cooler was cleaned, inspected and found to be in good condition. The system was refilled with fresh ethylene glycol-based solution.

In 2010 and 2013, the NRC performed the 71003 Phase II inspections at PBN Units 1 and 2, respectively. The inspectors verified that the program and program enhancements were in place to ensure: (1) maintenance of system corrosion inhibitor concentrations to minimize degradation; (2) periodic or one-time surveillance testing and inspections to evaluate system and component performance; and (3) inspection methods include visual testing, ultrasonic testing, and eddy current testing. Based on review of the timeliness and adequacy of PBN's actions, the inspectors determined that PBN satisfied the commitments associated with the Closed Treated Water AMP.

An effectiveness review of the PBN Closed Treated Water Systems AMP was performed in 2018 following the guidelines in NEI 14-12. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). The PBN Closed Treated Water Systems AMP was determined to continue to be effectively implemented. Although no gaps were identified, a revision to the AMP basis document was implemented to discuss the most recent program history (i.e., eddy current testing results).

In 2019, the NRC performed the 71003 Phase 4 inspections at PBN Units 1 and 2. The PBN Closed-Cycle Cooling Water System Surveillance Program was one of the seven AMPs selected for review, however, no findings were identified.

Quarterly health reports for the component cooling water system from January 2015 through February 2020 were evaluated as part of the SLRA OE review. The component cooling system received all "green" health reports. The quarterly health reports for the HV system (auxiliary/heating steam/condensate, chilled/hot water system) were also evaluated as part of the SLRA OE review, and this system also received all "green" health reports. Overall, the general health trend for the closed treated water systems has been and remains positive.

Other than the component cooling water heat exchanger tube vibration wear issues, there have been very few aging degradation related ARs associated with closed treated water systems. The existing water treatment programs for these systems have been effective in minimizing aging degradation and PBN has not experienced performance issues of its component cooling system or other closed treated water systems due to corrosion related loss of material, fouling, or cracking. Therefore, no enhancements are required with respect to the OE.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Closed Treated Water Systems AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Closed Treated Water Systems AMP, with the exceptions and enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.13 Inspection of Overhead Heavy Load Handling Systems

Program Description

The PBN Inspection of Overhead Heavy Load Handling Systems AMP is an existing AMP that was evaluated as a portion of the PBN Structures Monitoring AMP (Section B.2.3.34) in the initial license renewal application. The PBN Inspection of Overhead Heavy Load Handling Systems AMP is evaluated separately in the subsequent license renewal application and it is compared to the NUREG-2191, Section XI.M23 program.

Light load handling systems related to refueling at PBN include the reactor cavity manipulator cranes and the spent fuel pool bridge crane. These systems are not within the scope of subsequent license renewal because – as described in SLRA Section 2.4.15 – they do not have the potential to impact safety related components during normal plant operation.

The PBN Inspection of Overhead Heavy Load Handling Systems AMP evaluates the effectiveness of maintenance monitoring activities for cranes and hoists that are within the scope of SLR. This AMP addresses the inspection and monitoring of crane-related structures and components to provide reasonable assurance that the handling system does not affect the intended function of nearby safety-related equipment. Many crane systems and components are not within the scope of this AMP because they perform an intended function with moving parts or with a change in configuration, or they are subject to replacement based on qualified life.

The PBN Inspection of Overhead Heavy Load Handling Systems AMP includes periodic visual inspections to detect loss of material due to general corrosion and wear, deformed or cracked bridges, structural members, and structural components; and loss of material due to general corrosion, cracking, and loss of preload on bolted connections. NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” provides specific guidance on the control of overhead heavy load cranes. The activities to manage aging effects specified in this AMP utilize the guidance provided in American Society of Mechanical Engineers (ASME) Safety Standard B30.2, “Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist),” and other appropriate standards in the ASME B30 series. In addition, monitoring and maintenance of bridges, structural members, and structural components of load handling systems follow the maintenance rule requirements provided in Title 10 of the Code of Federal Regulations (10 CFR) 50.65 for other crane types.

NUREG-2191 Consistency

The PBN Inspection of Overhead Heavy Load Handling Systems AMP, with enhancements, will be consistent without exception to NUREG-2191, Section XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems.”

Exceptions to NUREG-2191

None.

Enhancements

The PBN Inspection of Overhead Heavy Load Handling Systems AMP will be enhanced as follows for alignment with NUREG-2191. Enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Update the PBN Inspection of Overhead Heavy Load Handling Systems AMP governing procedure to specify NUREG-0612 load handling systems.
3. Parameters Monitored or Inspected	Update the PBN Inspection of Overhead Heavy Load Handling Systems AMP governing procedure to clarify that the visual inspections for NUREG-0612 load handling systems monitor for loss of material due to wear.
4. Detection of Aging Effects	Update the PBN Inspection of Overhead Heavy Load Handling Systems AMP governing procedure to state that for the in-scope systems that are infrequently in service, such as containment polar cranes, periodic inspections are performed once every refueling cycle just prior to use. Also update the PBN Inspection of Overhead Heavy Load Handling Systems AMP governing procedure, inspection procedures, and/or preventive maintenance requirements for NUREG-0612 load handling systems to state their respective visual inspection frequencies required by the 2005 version of ASME B30.2. According to ASME B30.2, inspections are performed within the following intervals: o “Periodic” visual inspections by a designated person are required and documented yearly for normal service applications per paragraph 2-2.1.1. o A crane that is used in infrequent service, which has been idle for a period of one year or more, shall be inspected before being placed in service in accordance with the requirements listed in paragraph 2-2.1.3 (i.e., periodic inspection).
6. Acceptance Criteria	Update the PBN Inspection of Overhead Heavy Load Handling Systems AMP governing procedure to state that any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload for NUREG-0612 load handling systems is evaluated according to the 2005 Edition of ASME B30.2 or other applicable industry standard in the ASME B30 series.
7. Corrective Actions	Update the PBN Inspection of Overhead Heavy Load Handling Systems AMP governing procedure to state that repairs made to NUREG-0612 load handling systems are performed as specified in the 2005 Edition of ASME B30.2 or other appropriate standard in the ASME B30 series.

Operating Experience

Industry Operating Experience

There has been no history of corrosion-related degradation that threatened the ability of a crane to perform its intended function. Likewise, because cranes have not been operated beyond their design lifetime, there have been no significant fatigue-related structural failures. Operating experience indicates that loss of bolt preload has occurred, but not to the extent that it has threatened the ability of a crane structure to perform its intended function.

Plant Specific Operating Experience

Annual Summary reports are maintained for the Structures Monitoring Program, which includes the inspection and repair activities for load handling systems. These summary reports record conditions requiring evaluation or corrective action by building and status of the corrective action implemented for each. The PBN Structures Monitoring AMP (Section B.2.3.34) contains an overview of the annual summary reports.

The following review of plant-specific OE demonstrates how PBN is managing aging effects associated with the PBN Inspection of Overhead Heavy Load Handling Systems AMP.

- In 2012, the rail for the Unit 2 Polar Crane was observed to exceed allowable lateral movement by 0.25 inches for about 8 inches of circumferential travel. Structural engineers reviewed prior evaluations of similar lateral movement and determined that the additional 0.25 inches was acceptable. Subsequent adjustment of rail clips brought the section of rail back into conformance with the inspection criteria.

- In 2016, one of the fasteners on the RCP motor lifting device (1Z-994) was found damaged (bolt head broken off) while being inspected prior to use. A new bolt was installed.

- In 2018, inspections of the Unit 2 reactor vessel internals lifting rig noted large flakes of peeling paint in three areas along with some wear residue near the pin at the top of the device. Immediate action (i.e., removal of paint chips and residue) resolved foreign material exclusion concerns. Corrosion rate for the underlying steel is minimal (estimated at less than 10 mils/year) and does not challenge structural integrity. Refurbishment is planned prior to Unit 2 Refueling Outage 38 in 2021.

The PBN Structures Monitoring AMP has also been enhanced as a result of operating experience. Examples of improvements to the Structures Monitoring Program governing procedure are summarized in SLRA Section B.2.3.34.

OE will be reviewed such that if there is an indication that the aging effects are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Inspection of Overhead Heavy Load Handling Systems AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Inspection of Overhead Heavy Load Handling Systems AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.14 Compressed Air Monitoring

Program Description

The PBN Compressed Air Monitoring AMP is an existing program which monitors moisture content and contaminants in Instrument Air and performs opportunistic visual inspections of internal surfaces for loss of material. The following systems are in scope for the PBN Compressed Air Monitoring AMP:

- Instrument Air sub-system of the Plant Air System
- Diesel Starting Air sub-system (Train B only) of the Emergency Power System
- Gas Turbine Generator Instrument and Control Air sub-system of the Emergency Power System

The PBN Compressed Air Monitoring AMP also manages components which supply instrument air to the Containment Ventilation System, Main and Auxiliary Steam System, Feedwater and Condensate System, Auxiliary Feedwater System, and Containment Isolation System.

The PBN Compressed Air Monitoring AMP includes preventive monitoring of water (moisture), and other contaminants (particulate size and lubricant content) to keep within specified limits.

The PBN Compressed Air Monitoring AMP will manage loss of material due to corrosion in components downstream of air dryers in compressed air systems. Aging effects in locations upstream of the air dryers, including the non-dried Diesel Starting Air Train A, are managed by the PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP. In addition, the Service Air sub-system is in scope for the PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.

The PBN Compressed Air Monitoring AMP provides reasonable assurance that moisture is not collecting in compressed air systems or supplied components, and air quality is maintained so that loss of material is not occurring. Opportunistic visual internal inspections of compressed air system components will be performed in order to detect loss of material prior to a loss of intended function.

The PBN Compressed Air Monitoring AMP is based on relevant aspects of the PBN response to NRC GL 88-14 and INPO SOER 88-01. The PBN Compressed Air Monitoring AMP relies on the guidance from the most current ANSI/ISA standards, and will rely on the guidance in ASME OM-2012, Division 2, Part 28, and EPRI TR-10847 for testing and monitoring air quality and moisture. Additionally, inspection and test results will be trended to provide for the timely detection of aging effects prior to loss of intended function.

NUREG-2191 Consistency

The PBN Compressed Air Monitoring AMP, with enhancements, will be consistent with the ten elements of NUREG-2191, Section XI.M24, “Compressed Air Monitoring.”

Exceptions to NUREG-2191

None.

Enhancements

Element Affected	Enhancement
1. Scope of Program	• Compile a governing program procedure for the PBN Compressed Air Monitoring AMP to include the element by element requirements presented in NUREG-2191 Section XI.M24.
2. Preventive Actions	• Update the air quality sampling and/or governing procedure to incorporate the air quality provisions provided in the guidance of the Electric Power Research Institute (EPRI) TR-108147 and consider the related guidance in the American Society of Mechanical Engineers (ASME) OM-2012, Division 2, Part 28.
4. Detection of Aging Effects	• Update pertinent documents to include inspections of internal air line surfaces with maintenance, corrective, or other activities that involve opening of the component or system (For example, with air start valve inspections, check valve inspections, and relief valve or check valve replacements, or G05 air dryer filter checks). • Update pertinent documents to include inspection frequency and inspection methods for the opportunistic inspections with guidance of standards or documents such as ASME OM-2012, Division 2, Part 28
5. Monitoring and Trending	• Update the air quality sampling and/or governing procedure to review air quality test results. • Consider ASME OM-2012, Division 2, Part 28 for monitoring and trending guidance.

Operating Experience

Industry Operating Experience

In 2008, a plant incurred an unplanned reactor trip from a failure of a mechanical joint in the instrument air system (NRC IN 2008-06). The mechanical joint was a soldered connection on a 3-inch diameter instrument air line, which failed due to poor fabrication/installation and subsequent corrosion at the connection. The gap between the coupling and tube was too large, which caused the solder to settle at the bottom of the connection and solder flux to remain in the solder. The solder flux slowly corroded until the connection was weakened to the point of separation. As part of the PBN response to NRC IN 2008-06, PBN reviewed instrument air drawings and design guides, which required fittings to be silver brazed. A silver brazed connection provides a stronger joint compared to soldering, with high corrosion and heat resistance. Based on that review, no further actions were required in response to NRC IN 2008-06.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience including research and development such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

<u>Plant Specific Operating Experience</u>

Action Requests

- May 2016: Instrument Air system sampling results indicated that four particles larger than the 40-micron particle size limit were found. Laboratory analysis indicated that the large particles were most likely thread sealant, which was also found in January 2016. The potential impact of the identified larger particles was determined to be insignificant to the operation of Instrument Air downstream components due to the local inline filters (which filter down to 5 microns), and restriction from these limited particles would be inconsequential. As a corrective action, Engineering processed a procedure change to require a 15-minute blowdown at the sample points prior to taking any air samples. In addition, PMs were created to periodically replace the in-line filters and require quarterly sampling of the system.

- November 2011: Many of the DA system check valves had PMs developed to periodically replace the valves, based on OE which found the check valves sticking open during inservice testing. These PMs provide for periodic opportunistic inspections of the DA system under the PBN Compressed Air Monitoring AMP.

Program Owner Discussions

- On February 5th and 6th, 2020, interviews were held with system engineers and the PBN Compressed Air Monitoring AMP Owner.

- The Train A EDG starting air system does not use an air dryer, therefore the Train A EDG starting air system will be managed under the PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP. The Train B EDG starting air system has dryers and there have been no issues associated with those tanks. The EDG starting air tanks for both trains are blown down periodically in order to clear any condensed water in the tanks and to reduce the threat of internal corrosion.

  The IA system currently has PMs which swap out the desiccant in the instrument air dryers in order to maintain the appropriate dewpoint in the system, and quarterly sampling is performed for instrument air. Sampling locations are the north header, south header, and two MFIV locations. Air receivers for the IA system are also blown down periodically.

System / Program Health Reports

- Instrument Air System Health: Currently yellow due to being in maintenance rule (a)(1) status after the K-3B service air compressor exceeded its performance criteria for component monitoring failures. Prior to this, and dating back to 2015, the Instrument Air system has been in green and white status, with the periods of white also related to service air compressor K-3B and associated component failures. Note that the Service Air System is managed by the PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP. A system dryer was installed for the Service Air System in 2018, and the tie to the loader and unloader valves were moved downstream of the dryer.

- Diesel Generator System (includes Diesel Starting Air): Dating back to 2015, the Diesel Generator System has been in green status. The Diesel Starting Air system does not have its own system health report; therefore, the Diesel Generator System health reports were reviewed to assess system health and performance.

Program Assessments and Evaluations

- The existing Compressed Air Monitoring program activities credited for SLR are currently part of the Periodic Surveillance and Preventive Maintenance Program, therefore, AMP effectiveness reviews for that program provide some insight into the aging management of the in-scope systems. The AMP was reviewed against the criteria in NEI 14-12, and the AMP was found to be effective at managing the effects of aging, with gaps identified which were either administrative in nature or not associated with the in-scope systems.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Compressed Air Monitoring AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Compressed Air Monitoring AMP will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.15 Fire Protection

Program Description

The PBN Fire Protection AMP is an existing AMP, formerly a portion of the PBN Fire Protection Program. This AMP manages aging effects (loss of material, cracking, and loss of seal) associated with fire barriers and non-water suppression systems (halon and dry chemical systems). The PBN Fire Protection AMP includes fire barrier inspections. The fire barrier inspection portion of this AMP requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, floors, fire damper assemblies, electrical raceway fire barrier systems, well-sealed robustly secured components, fully enclosed cable tray covers, fire proofing material sprayed onto structural steel, as well as periodic visual inspection and functional tests of fire-rated doors so that their operability is maintained. The PBN Fire Protection AMP also requires periodic visual inspection of other passive fire protection features credited for the Fire Protection Program like oil collection channels, trenches, and skids. The PBN Fire Protection AMP also includes periodic inspection and testing of the halon fire suppression systems and dry chemical fire extinguishing systems.

With respect to preventive actions, PBN has adopted the National Fire Protection Association (NFPA) 805 fire protection program to meet the requirements of 10 CFR 50.48(c) and ensure that regulatory requirements are met for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability for each fire area containing SSCs important to safety.

Inspection results are acceptable if there are no signs of degradation that could result in the loss of the fire protection capability due to loss of material or elastomer degradation. The acceptance criteria include:

- No visual indications (outside of those allowed by approved penetration seal configurations) of cracking, separation of seals from structures and components, indications of increased hardness, shrinkage, loss of strength, or ruptures or punctures of seals;
- No significant indications of cracking, loss of material, and changes to elastomer properties of fire barrier walls, ceilings, floors, passive fire protection features credited by the fire protection program, and in other fire barrier materials;
- No visual indication of loss of material on fire damper assemblies;
- No visual indications of missing parts, holes, and wear; and
- No deficiencies in the functional tests of fire doors (i.e., the door swings easily, freely, and achieves positive latching).

Periodic inspections and testing of the halon fire suppression systems and dry chemical fire extinguishing systems are performed to demonstrate that it is functional, and the surface condition of components is inspected for corrosion, nozzle obstructions, and other damage.

Visual inspection of at least 10 percent of each type of sealed penetration is performed at a frequency of every 18 months, which is in accordance with the NRC-approved fire protection program. Visual inspections on fire-rated structures (fire barrier walls, ceilings, and floors) are conducted at a frequency of at least once every five years. Visual inspections on combustible liquid spill retaining features (oil collection channels, trenches, and skids) are conducted at a frequency of at least once every 18 months. Visual inspections of fire-rated assemblies (electrical raceway fire barrier systems, well-sealed robustly secured components, fully enclosed cable tray covers, and fire proofing material sprayed onto structural steel) are conducted at a frequency of at least once every 54 months (approximately 33 percent of each type per refuel cycle). Periodic visual inspections and functional tests are conducted on fire doors and their closing mechanism and latches are verified functional at least once per 6 months. Visual inspection on 10 percent of the fire damper assemblies are conducted at a frequency of once every 18 months, which is in accordance with the NRC-approved fire protection program.

The results of inspections and functional testing of the in-scope fire protection equipment are collected, analyzed, and summarized by engineers in health reports. The system and program health reporting procedures identify adverse trends and prescribe preemptive corrective actions to prevent further degradation or future failures. When performance degrades to unacceptable levels, the PBN CAP is utilized to drive improvement. During the inspection of penetration seals and fire damper assemblies, if any sign of abnormal degradation is detected within the sample, the inspection sample size is expanded, in accordance with the approved PBN fire protection program, to include an additional 10 percent of each type of sealed penetration or fire damper assembly.

NUREG-2191 Consistency

The PBN Fire Protection AMP, with enhancements, will be consistent with the 10 elements described in NUREG-2191, Section XI.M26, “Fire Protection.”

Exceptions to NUREG-2191

None.

Enhancements

The PBN Fire Protection AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria	Enhance plant procedures to specify that penetration seals will be inspected for indications of increased hardness, shrinkage and loss of strength.

Element Affected	Enhancement
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria	Enhance plant procedures to specify that any loss of material to the fire damper assembly is unacceptable.
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria	Enhance plant procedures to specify that well-sealed and robustly secured components and fully enclosed cable tray covers credited to prevent internal fires from propagating outside of the component, and fire proofing material sprayed onto structural steel will be inspected for loss of material, cracking, and changes to elastomer properties as appropriate.
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria	Enhance plant procedures to add spalling and scaling to the degradation effects for which masonry block walls are inspected.
4. Detection of Aging Effects	Enhance plant procedures to indicate that personnel preforming FP inspections will be qualified to do so.
4. Detection of Aging Effects	Enhance plant procedures to state that at least 10 percent of each **type** of seal will be visually inspected every 18 months.
4. Detection of Aging Effects	Enhance plant procedures to specify that well-sealed and robustly secured components and fully enclosed cable tray covers credited to prevent internal fires from propagating outside of the component, and fire proofing material sprayed onto structural steel will be inspected every 4.5 years (33% of the population every 18 months).
4. Detection of Aging Effects	Enhance plant procedures to specify that the dry chemical fire extinguishing systems will be inspected semi-annually.
5. Monitoring and Trending	Enhance plant procedures to specify that the dry chemical fire extinguishing system inspections will be monitored and trended.
5. Monitoring and Trending	Enhance plant procedures to include monitoring and trending of oil collection channels, trenches, and skids credited to mitigate the spread of combustible liquids for cracking and loss of material.
5. Monitoring and Trending 7. Corrective Actions	Enhance plant procedures to require an inspection of an additional 10 percent of a type of seal when more than 15 percent of the sample population does not meet any acceptance criteria during the 18-month inspection period.

Operating Experience

Industry Operating Experience

PBN evaluates industry operating experience (OE) items for applicability per the NextEra Fleet OE Program and takes corrective actions, when necessary. For example:

- Industry OE (NRC Information Notices 88-56, 94-28, and 97-70) has shown that silicone foam fire barrier penetration seals have experienced splits, shrinkage, voids, lack of fill, and other failure modes.
- Degradation of electrical raceway fire barriers such as small holes, cracking, and unfilled seals have also been found on routine walkdowns as documented in IN 91-47 and GL 92-08. (Note: PBN does not use Thermo-Lag Fire Barrier Material.)
- Fire doors have experienced wear of the hinges and handles.

Plant Specific Operating Experience

The following summary of site-specific OE (which includes review of corrective actions and NRC inspections) provides examples of how PBN is managing aging effects associated with the PBN Fire Protection AMP.

- During work to install fire wrap on conduit, insulation was removed from an adjacent mechanical pipe. Once the insulation had been removed the underlying penetration seal was found to be degraded. Fire rounds were started and an evaluation was performed by the fire protection engineer to determine functionality. The work order was modified to require repair of the degraded seal. The degraded seal was repaired and 3-hour fire wrap re-installed on the conduits.
- During a Fire Protection audit, the center of a blockout was noticed to have a crack running vertically from the very bottom to the top where in comes into contact with a penetration. The crack was approximately 1/16 inch wide. An additional crack was found to run between two penetrations. The grout around the penetration and to a lesser extent around the adjacent penetrations was damaged with pieces missing. The cracking was inspected by the fire protection engineer, and he determined that the condition was functional for fire protection purposes but recommended that the condition be corrected.
  - A structural evaluation was performed and indicated that the crack was located within the middle of the fill for the wall blockout. The crack was through wall as it could be seen from the other side of the 18” thick block wall. The crack formed at the weakest point of the fill in the middle due to shrinkage. The crack was determined to be acceptable as it is in the fill material, and the fire protection engineer confirmed that the crack was not a fire protection issue for the wall. The fire protection engineer also confirmed

that the delaminated concrete around the penetrations could be corrected with a cosmetic patch.

- A fire/HELB barrier penetration was installed and after 24-hour curing was complete; the cured pour was inspected for cracks and shrinkage. One side of the penetration was acceptable, but the other side had a crack which ran from approximately 100 to 240 degrees. Based on discussion with Nuclear Assurance and photos of the penetration after removing the grout forms and surface cleaning, structural engineering indicated that the cracking observed at the lower third of the penetration perimeter was superficial and non-structural cracking related to drying shrinkage of the near surface layer. The method of forming left a thin layer of latent grout on the surface of the wall immediately outside the perimeter of the penetration. The latence was partially removed by sanding and the crack was visible as a discoloration but appeared to be filled. This was likely due to moisture distribution in the newly placed grout. Cracking due to drying in thin sections of grout is common and there are manufacturer guidelines in place for structural grout placement. In this case the latence was not structural and did not impact the structure of the penetration. The grout in the penetration itself could reasonably be expected to be uniform, well cured, bonded to the substrate and structurally acceptable for service as a penetration barrier. Based on this review no further structural engineering actions were required.

- A penetration was found to have surface cracking. Based on a review of pictures of the penetration and past satisfactory performance from fire barrier inspections, the fire protection engineer determined that the cracking was cosmetic with flaking in the white inspection coating and did not impact functionality of the penetration.

- In October 2010 and March 2013, the NRC completed post approval inspections for license renewal at PBN. The inspectors verified that new fire protection implementing documents were established to implement inspections of selected components and of the fire suppression piping. The inspectors reviewed the licensing basis, program basis document, and existing implementing procedures. The inspectors verified that the above enhancements were incorporated into the existing program documents and implementing procedures. The PBN Fire Protection AMP was determined to continue to be effectively implemented with no gaps identified.

- An AMP effectiveness review was performed in 2018 following the guidelines in NEI 14-12. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). The PBN Fire Protection AMP was determined to continue to be effectively implemented with no gaps identified.

To date, no enhancements to the AMP have been identified as a result of OE. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Fire Protection AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Fire Protection AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.16 Fire Water System

Program Description

The PBN Fire Water System AMP is an existing AMP, previously part of the Fire Protection Program, that manages the aging effects of loss of material, wall thinning, cracking, and flow blockage due to fouling for water-based fire protection system components. This objective is achieved through conducting periodic visual inspections, tests, and flushes performed in accordance with the 2011 Edition of the National Fire Protection Association Code, NFPA 25 (Reference 1.6.66).

PBN Fire Water System AMP applies to water-based fire protection system components, including sprinklers; nozzles; fittings; valve bodies; fire pump casings; hydrants; hose stations; standpipes; water storage tanks; and aboveground, buried, and underground piping and components that are tested in accordance with the NFPA codes and standards. Full-flow testing and visual inspections are conducted in order to ensure that loss of material, cracking, and flow blockage are adequately managed. In addition to NFPA codes and standards, portions of the water-based fire protection system that are: (a) normally dry but periodically are subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect, are subjected to augmented testing or inspections. Also, portions of the system (e.g., fire service main, standpipe) are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions are initiated.

The following AMP supplement the PBN Fire Water System AMP in managing aging of the fire water system components. The PBN Bolting Integrity AMP is used to manage aging of the closure bolting associated with the fire water system. The PBN Buried and Underground Piping and Tanks AMP is used to manage aging of the external surfaces of buried and underground fire water system piping. The PBN External Surfaces Monitoring of Mechanical Components AMP is used to manage aging of the above-ground fire water system piping surfaces. The PBN Selective Leaching AMP is used to and manage aging of surfaces within the fire water system that have a material-environment combination susceptible to selective leaching. The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is used to manage aging of all internal surface coatings applied to fire water system components.

Fire water systems are regularly flushed to remove blockage and obstructions such as corrosion products and sediment. The PBN Fire Protection Plan outlines the procedures and surveillance intervals associated with periodic flushing:

- The fire hydrants and underground fire water main are flow tested/flushed at least once every 12 months. The fire water accumulator tank is flushed once a month and internally inspected every 2 years.
- The automatic spray nozzles and sprinklers are inspected for paint, corrosion, damage, obstruction, and/or physical defects, at least once every 3 months during the respective sprinkler/spray system alarm test and flush. Flushes/tests of sprinklers and spray nozzles are performed periodically and frequencies vary based on the suppression system.

- All fire hose stations are flow tested/flushed at least every three years, although some hoses and stations are tested more frequently. Hose stations are also visually inspected on a monthly interval.

The PBN Fire Water System AMP also utilizes preventive actions which include chemical treatment via a chlorination system that injects oxidizing biocide, silt dispersant, and bio detergent into the service water and fire water systems to control silt deposition, microbiologically-influenced corrosion (MIC), and macroscopic biofouling from biota such as mussels.

To address potential loss of material, cracking, and flow blockage, the PBN Fire Water System AMP monitors several fire water system parameters. The ability to maintain required system pressures, flow rates, and required internal conditions (i.e., no fouling or sediment blockage) is required to be tested annually. These tests also verify that the diesel-driven and the electric motor-driven fire pumps are performing adequately and meet their design requirements. Occurrences of pipe/component leakage are also visually identified during these tests. Visual examinations of cementitious materials are not applicable, since no cementitious materials are used in the PBN fire water system.

The fire protection system pressure is continuously monitored. Test results from the various surveillance tests are evaluated. Periodic full flow flushing of the main fire system underground piping is performed to assure that the system function is maintained. Any degradation identified either by visual inspections or as a result of testing is reported, evaluated, and corrected through the PBN corrective action program. Acceptance criteria are defined in the PBN Fire Water System AMP procedures used to perform the respective tests and inspections.

If an obstruction inside piping or sprinklers is detected during pipe inspections, the material is removed and the inspection results are entered into the PBN corrective action program for further evaluation. An evaluation is conducted to determine if deposits need to be removed to determine if loss of material has occurred. When loose fouling products that could cause flow blockage in the sprinklers is detected, a flush is conducted in accordance with the guidance in NFPA 25 Appendix D.5, "Flushing Procedures." If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the PBN corrective action program.

NUREG-2191 Consistency

The PBN Fire Water System AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M27, "Fire Water System."

Exceptions to NUREG-2191

None

Enhancements

The PBN Fire Water System AMP will be enhanced as follows, for alignment with NUREG-2191. This AMP is to be implemented and its inspections and tests begin no earlier than 5 years prior to the SPEO. The inspections and tests are to be completed no later than six months prior to entering the SPEO or no later than the last refueling outage prior to the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Update the governing AMP procedure to clearly state which procedures perform visual inspections for detecting loss of material. Such visual inspections will require using an inspection technique capable of detecting surface irregularities that could indicate an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric wall thickness examinations shall be performed.
3. Parameters Monitored or Inspected	Update the governing AMP procedure to clearly state which procedures perform volumetric wall thickness inspections. Volumetric inspections shall be conducted on the portions of the water-based fire protection system components that are periodically subjected to flow but are normally dry.
4. Detection of Aging Effects	Update existing procedures and create new procedures to incorporate the surveillance requirements stated in NUREG-2191, Section XI.M27, Element 4 and Table XI.M27-1 based on NFPA 25, 2011 edition.
5. Monitoring and Trending	Update the governing AMP procedure and trending procedure to state that where practical, degradation identified is projected until the next scheduled inspection. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation. Results of flow testing, flushes, and wall thickness measurements are monitored and trended by either the Engineering or Fire Protection Department per instructions of the specific test/inspection procedure. Degradation identified by flow testing, flushes, and inspections is evaluated. If the condition of the piping/component does not meet acceptance criteria, then a condition report is written per the PBN corrective action program and the component is evaluated for repair/replacement. For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation.
5. Monitoring and Trending	Update the governing AMP procedure to identify the procedure that performs the continuous monitoring and evaluation of the fire water system discharge pressure.
5. Monitoring and Trending	Update the governing AMP procedure to state that results of flow testing (e.g., buried and underground piping, fire mains, and sprinkler), flushes, and wall thickness measurements are monitored and trended. Degradation identified by flow testing, flushes, and inspections is evaluated.
6. Acceptance Criteria	Update the governing AMP procedure to state that the minimum design wall thicknesses of the in-scope piping must be maintained.

Element Affected	Enhancement
6. Acceptance Criteria	Update the governing AMP procedure to point to the inspection procedures which inspect the wall thicknesses and compare to the minimum design thicknesses.
7. Corrective Actions	Update the flow test procedure and develop a new main drain test procedure to state that if a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation, then additional tests are conducted. The number of increased tests is determined in accordance with the PBN corrective action program; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval (i.e., 5 years, annual) in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent-of-condition and extent-of-cause analysis is conducted to determine the further extent of tests. Since PBN is a multi-unit site, additional tests include inspections at all of the units with the same material, environment, and aging effect combination.

Operating Experience

Industry Operating Experience

Operating experience (OE) shows that water-based fire protection systems are subject to loss of material due to corrosion, MIC, or fouling; and flow blockages due to fouling. Loss of material has resulted in sprinkler system flow blockages, failed flow tests, and piping leaks. Inspections and testing performed in accordance with NFPA standards coupled with visual inspections are capable of detecting degradation prior to loss of intended function. The following OE was listed in NUREG-2191, Section XI.M27, as relevant to the PBN Fire Water System AMP:

- In October 2004, a fire main failed its periodic flow test due to a low cleanliness factor. The low cleanliness factor was attributed to fouling because of an accumulation of corrosion products on the interior of the pipe wall and tuberculation. Subsequent chemical cleaning to remove the corrosion products from the pipe wall revealed several leaks. Corrosion products removed during the chemical cleaning were observed to settle out in normally stagnant sections of the water-based fire protection system, resulting in flow blockages in small diameter piping and valve leak-by. (References ML12220A162, ML12306A332, and ML13029A244).

- In October 2010, a portion of a preaction spray system failed its functional flow test because of flow blockages. Two branch lines were found to have significant blockages. The blockage in one branch line was determined to be a buildup of corrosion products. A rag was found in the other branch line. (Reference ML13014A100).

- In August 2011, an intake fire protection preaction sprinkler system was unable to pass flow during functional testing. Subsequent visual inspections identified flow blockages in the inspector’s test valve, the piping leading to the inspector’s test valves, and three vertical risers. The flow blockages were determined to be a buildup of corrosion products. (Reference ML113050425).

- In March 2012, the staff and licensee personnel found that a portion of the internally galvanized piping of a 6-inch preaction sprinkler system could not be properly drained because the drainage points were located on a smaller diameter pipe that tied into the side of the 6-inch pipe. A boroscopic inspection of the lower portions of the pipe showed that it contained residual water, that the galvanizing had been removed, and that significant quantities of corrosion products were present whereas in the upper dry portions, the galvanized coating was still intact. (Information Notice 2013-06).

Plant Specific Operating Experience

Between 2010 and 2020, several action requests (ARs) were initiated to evaluate and/or correct degradation or programmatic issues related to the PBN fire water system.

- In November 2012, the north and south fire protection supply headers were constantly submerged in water and exhibited surface corrosion at the above ground to below ground transition pits inside the pumphouse. A determination was made that the exterior should be examined, then cleaned and coated and a work order was initiated to perform the corrective action. In January 2019, water was once again identified in these fire protection piping chases, and another work order was initiated to pump out the chase and perform a repair.

- In March 2013, in response to an NRC Information Notice, IN 2013-06, involving the loss of function of fire protection sprinkler systems with the potential for air-water interactions at a different plant, an AR was initiated. Based on the review of NRC IN 2013-06, there were two location susceptible to the wet-dry cycle and these locations were evaluated. A section of normally dry pre-action piping was determined to potentially have water causing internal corrosion at a low point. As a result of the evaluation, a preventive maintenance activity was generated to routinely inspect the branch section of piping.

- In September 2013, during performance of the monthly walk-down of a housekeeping area, the overhead fire sprinkler piping was thought to be leaking from the last branch connection at the North end of the overhead sprinkler piping in the water treatment grating area. The area was walked down later in the week, but no leaks were found. The observed wetness was believed to be pipe sealant or condensation rather than internal corrosion.

- In May 2018, as part of an extent of condition assessment under the service water inservice inspection program due to a pinhole (through wall) leak at the upstream weld of a valve, inspections were performed on the piping upstream. Some substantial localized pitting was identified and the piping and valve were replaced.

There were several ARs related to the fire protection system and/or the NFPA 805 transition, however most of these were not related to aging/degradation of the fire water system (e.g., administrative, configuration control, electrical, fire barriers).

An effectiveness review of the PBN Fire Protection Program was performed in 2018 following the guidelines in NEI 14-12. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). Gaps identified were related to the transition to NFPA 805 licensing basis and not the AMP. The AMP was deemed to be effective.

The quarterly fire protection program health reports from January 2015 through February 2020 were evaluated as part of the SLRA OE review. Although the most recent fire protection program health reports were scored “white,” PBN has an opportunity to achieve a “green” status after entering the monitoring period when all of the NFPA 805 criteria are met.

In 2010 and 2013, the NRC performed the 71003 Phase 2 inspections at PBN Units 1 and 2 respectively. The inspectors verified that new implementing documents were established to implement inspections of selected components and of the fire suppression piping. Based on review of the timeliness and adequacy of PBN’s actions, the inspectors determined that PBN met commitments related to the fire protection AMP.

In 2019, the NRC performed the 71003 Phase 4 inspections at PBN Units 1 and 2. The PBN Fire Protection Program was not one of the seven AMPs selected for review, therefore, no findings were identified.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Fire Water System AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Fire Water System AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.17 Outdoor and Large Atmospheric Metallic Storage Tanks

Program Description

The PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP is an existing AMP that consolidates and coordinates existing activities for subject tanks that are associated with the following AMPs credited for the original renewed licenses:

- Tank Internal Inspection Program
- Structures Monitoring Program
- Systems Monitoring Program
- Water Chemistry Control Program
- Fuel Oil Chemistry Control Program
- One-Time Inspection Program

This AMP manages aging effects associated with outdoor tanks sited on concrete and indoor large-volume tanks (100,000 gallons or greater) containing water designed with internal pressures approximating atmospheric pressure that are sited on concrete. The tanks included within the scope of this AMP are as follows:

- 1T-013, Refueling Water Storage Tank (RWST)
- 2T-013, Refueling Water Storage Tank (RWST)
- T-021, Reactor Makeup Water Tank (RMWT)
- T-032A, Fuel Oil Storage Tank (FOST)
- T-032B, Fuel Oil Storage Tank (FOST)

This AMP manages loss of material and cracking by conducting periodic internal and external visual and surface examinations. Surface exams are conducted to detect cracking when susceptible materials are used. Thickness measurements of tank bottoms are conducted to detect degradation and ensure corrosion from the inaccessible undersides will not cause a loss of intended tank function.

The external surfaces of insulated tanks will be periodically inspected using a sampling of inspection points. Inspections will be conducted in accordance with ASME Code Section XI requirements as applicable or are conducted in accordance with plant-specific procedures that include inspection parameters such as lighting, distance, offset, and surface conditions. Both the carbon steel and the stainless steel tanks will have external visual inspections performed every refueling outage. The tank bottom thickness measurements will be performed at a 10-year frequency.

Where practical, identified degradation will be projected until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the component intended functions throughout the SPEO based on the projected rate of degradation. Applicable operating experience or inspection results may also be used to justify performing the periodic inspections more frequently.

The acceptance criteria for the internal visual inspection and bottom thickness of the tanks are the design corrosion allowance for the tank. Thus, any loss of material greater than the corrosion allowance for the tanks, as specified on the design drawings, requires evaluation or corrective action to ensure that the component intended functions of the tanks are maintained under all CLB design conditions. Results will be evaluated against acceptance criteria for the in scope tanks to confirm that the timing of the subsequent inspections will maintain the component intended functions throughout the SPEO based on the projected rate of degradation. Acceptance criteria for the tank to concrete interface inspection are to confirm there are no signs of degradation (minimal corrosion) or water intrusion. Any degradation of paints, coatings, or tank diaphragms or evidence of corrosion is reported and further evaluation is required to determine if repair or replacement of the paints, coatings, or tank diaphragms should be conducted. Any deficiencies are documented, evaluated, and repaired as necessary.

Additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). The number of increased inspections is determined in accordance with the PBN corrective action program; however, for inspections where only one in-scope tank of a material and environment combination is inspected, all tanks in that grouping will be inspected, including tanks from both units.

NUREG-2191 Consistency

The PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M29, “Outdoor and Large Atmospheric Metallic Tanks.”

Exceptions to NUREG-2191

None

Enhancements

The PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP will be enhanced as follows, for alignment with NUREG-2191. This AMP is to be implemented and its inspections and tests begin no earlier than 10 years prior to the SPEO. The inspections and tests are to be completed no later than six months prior to entering the SPEO or no later than the last refueling outage prior to the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Ensure that caulking or sealant is applied to the concrete-to-tank interface for the FOSTs, T-032A and T-032B, prior to the SPEO.
3. Parameters Monitored or Inspected; 4. Detection of Aging Effects 5. Monitoring and Trending; 6. Acceptance Criteria 7. Corrective Actions	Create a new procedure, and/or associated preventive maintenance requirements (PMRQs), to: • Address the interfaces, handoffs, and overlaps between the PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP and the following AMPs: o PBN Structures Monitoring AMP; o PBN External Surfaces Monitoring of Mechanical Components AMP; o PBN Water Chemistry AMP; o PBN Fuel Oil Chemistry AMP; o PBN One-Time Inspection AMP;

Element Affected	Enhancement
	o PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP. • Direct periodic (every refueling outage) visual inspection of FOST to concrete caulking/sealants, with mechanical manipulation as appropriate. • Direct periodic (10-year) surface examination of an RWST's external surface for evidence of cracking, with insulation removed, at the locations most susceptible to degradation and leakage. • Direct periodic (10-year) bottom thickness measurement of an RWST and the RMWT using low-frequency electromagnetic testing (LFET) techniques with follow-on ultrasonic testing (UT) examination, as necessary, at discrete tank locations identified by LFET. • Direct periodic (10-year) visual inspections of an RWST's nonwetted surface for evidence or loss of material and cracking. If evidence of cracking is identified, then a surface examination is also performed to determine the extent of the cracking. For the RMWT, direct periodic (10-year) visual inspections of the RMWT interior above the diaphragm for evidence of loss of material. • Clarify that subsequent inspections are conducted in different locations unless the PBN OLAMST AMP includes a documented basis for conducting repeated inspections in the same location. • Clarify that inspections and tests are performed by personnel qualified in accordance with site procedures to perform the specified task. • Clarify that non-ASME Code inspections and tests follow site procedures that include considerations such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes. • Clarify that where practical, identified degradation is projected until the next scheduled inspection. • Clarify that results are evaluated against acceptance criteria to confirm or adjust timing of subsequent inspections. • State the acceptance criteria as follows: a. No degradation of paints or coatings (e.g., cracking, flakes, or peeling), insulation/jacketing, or the RMWT internal diaphragm. b. No non-pliable, cracked, or missing caulking/sealant for the FOST-concrete interface. c. No indications of cracking of an RWST. d. No tank bottom thickness measurements or thickness projections less than the design thickness and/or no exceedance of the corrosion allowance. • State the appropriate corrective actions to perform for when degradation (e.g., sealant/caulking flaws, paint/coating flaws,

Element Affected	Enhancement
	loss of material, cracking, etc.) is identified, which include the following: a. Report degradation via a condition report (CR) then perform an engineering evaluation. b. Repair or replace the degraded component as determined by engineering evaluation and perform follow-up examinations. c. Expand the inspection to include both tanks (for FOST or RWST degradation). d. Double the sample size (for RWST surface examination degradation). Sample expansion inspections that happen in the next inspection interval are part of the preceding interval.
4. Detection of Aging Effects	Perform baseline LFET tank bottom thickness examinations of an RWST and the RMWT, with follow-on UT at discrete locations, and a baseline sample surface examination of an RWST tank exterior (with insulation temporarily removed).

Operating Experience

Industry Operating Experience

There have been instances within the nuclear industry that have involved tank defects such as wall thinning, cracks, pinhole leaks, through-wall flaws, as well as internal blistering, coating delamination, rust stains, and holiday which are frequently identified on tank bottoms. This industry operating experience (OE) provided clear examples to check for with respect to the site-specific OE review. With respect to these issues, PBN has experienced some coating/paint delamination and some rusting/corrosion on the subject tanks, but none that threatened the function of the tanks.

Plant Specific Operating Experience

A recent operating experience search was performed for SLR which covered a date range of January 1, 2011 through January 1, 2020. This search was supplemented using the NextEra NAMS system to identify action requests (ARs) linked to tank 1T-013, 2T-013, T-021, T-032A, and T-032B, which also included ARs prior to 2011. This search identified several ARs related to the in-scope tanks:

- RWSTs, 1T-013 and 2T-013:
    - In April 2007, while removing a heat exchanger, a load shift occurred that caused the bridge trolley to slide on the bridge beam to the north trolley stops. This caused the heat exchanger to swing and strike the insulation on the RWST. As part of the immediate corrective actions, the insulation was removed and the affected area of the RWST was inspected. The damage was only to the aluminum insulation cover of the RWST. The tank itself showed no evidence of being struck. The insulation was subsequently repaired and reinstalled.

   - During this time period, there were several ARs created due to unexpected water level drops and spurious water level alarms. None of these ARs were attributed to loss of pressure boundary in the tank due to aging, rather, the alarms were likely due to circuitry or equipment alignment. There were other ARs related to low water temperature, stripped heater terminal screws, and housekeeping, but none of these were related to aging of the tanks.

- RMWT, T-021
  - In September 2017, it was identified that the RMWT diaphragm had pillowed out from the sides of the tank and was bulging upward a foot away from the manhole. A normal looking diaphragm would look like the diaphragm was vacuum sealed to the top of the water with no bubbles or water on top. A work order inspected the condition and identified no water on top. The work order then used a vacuum pump to evacuate non-condensable gas and return the diaphragm to normal configuration. A similar issue occurred again in September 2018. This issue is caused by a new water treatment system that does not deaerate. The increased reactor makeup water temperatures due to reactor coolant pump seal issues was causing gasses to accumulate in the tank. Another work order also used a vacuum pump to evacuate non-condensable gas and return the diaphragm to normal configuration. In response to these issues, the RMWT is currently inspected for gas buildup every 6 months.
  - During this time period, there were several other ARs related to the RMWT, but none of these ARs were related to aging of the tanks.

- FOSTs, T-032A and T-032B
  - In May 2009, it was identified that tanks T-032A and T-032B had peeling paint and corrosion around the bottom lip of the tanks. The tanks were repainted, and a volumetric thickness examination was scheduled. The volumetric inspection performed in 2009 for each of these tanks showed that the measured wall thickness was adequate.
  - In November 2010, a license renewal credited internal visual inspection of FOST T-032A identified delamination of the internal coating that was originally applied in 2000. It was determined that since the rest of the coating was in excellent condition, the areas of delamination were likely due to inadequate surface preparation prior to the coating. In 2011, the earth berm associated with the FOSTs was repaired/upgraded so that it could be used as a secondary containment for the FOST contents for Wisconsin Administrative Code (WAC) requirements. Therefore, the coating was left as-is and the tank was returned to service. The 10-year internal inspections of the FOSTs are scheduled to be performed in 2020. These internal inspections will provide additional rate-of-degradation information to the PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP.

- In November 2016, it was identified that the FOSTs, T-032A and T-032B, were experiencing external paint peeling, rusting and pitting corrosion. A work request was initiated to evaluate if recoating was required. It was determined that the coating would be re-evaluated periodically.

- There were multiple ARs that identified small rodent burrows of the soil and liners associated with the T-032A and T-032B earthen berms. The first occurrence was identified in July 2009 during performance of the weekly T-032A and T-032B oil leakage check. The work request to repair the berm was completed in June 2011. In August and September 2017, additional rodent burrows and soil erosion were identified during the weekly T-032A and T-032B oil leakage check. An engineering change was initiated to replace the liner and restore the berm. The EC was closed out March 27, 2018. The PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP does not manage aging of the earthen berm around the tank, but rather, aging management of the berm will be provided by the PBN Structures Monitoring AMP.

- In June 2018, it was identified that soil erosion was occurring on the recently repaired T-032A and T-032B earthen berms. The sod that was planted in December 2017 had not become established. A “minor maintenance” work request was subsequently initiated in June 2018 and the maintenance will be completed. This minor maintenance request has no impact on the FOSTs or the concrete they rest upon.

The site operating experience previously discussed shows that the in-scope tanks have experienced no major issues that would jeopardized the health of their respective systems. This is a positive reflection of the respective AMP.

The 2018 effectiveness review for the PBN Tank Internal Inspection Program did not consider tanks 1T-013, 2T-013, T-021, T-032A, and T-032B which are now added to the scope of the PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP. Rather, these tanks were within the scope of the following programs, which were also determined to be effective (or, in the case of the One-Time Inspection Program, not require an evaluation) and did not have any tank-specific gaps:

- Structures Monitoring Program (Section B.2.3.34),
- Systems Monitoring Program (Section B.2.3.23),
- Water Chemistry Control Program (Section B.2.3.2),
- Fuel Oil Chemistry Control Program (Section B.2.3.18),
- One-Time Inspection Program (Section B.2.3.20).

Since the in-scope tanks are related to the fuel oil system, safety injection system, and chemical and volume control system (CV), the health reports for these systems as well as the structures monitoring program are the most relevant to the PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP. The respective health reports from January 2015 through February 2020 were reviewed. There are currently no quarterly health reports for the fuel oil system. The analysis of the quarterly safety injection system health reports shows that these were generally “green” and did not mention the in-scope tanks. Likewise, the CV health reports also generally yielded “green” scores, and the only discussion related to the RMWT, T-021, was for a respective level transmitter that required calibration. The structures monitoring program health reports also generally yielded “green” scores. The structures monitoring program health reports repeated the previously discussed erosion/rodent degradation issues for the earthen berms associated with FOSTs T-032A and T-032B but did not discuss the RMWT or RWSTs.

The NRC 71003 Phase 2 and Phase 4 inspection reports from 2010, 2012, 2013, and 2019 reviewed the existing programs that the PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP is based on. These inspection reports did not identify any elements specific to the PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP that would require an enhancement for SLR.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.18 Fuel Oil Chemistry

Program Description

The PBN Fuel Oil Chemistry AMP is an existing AMP, previously known as the Fuel Oil Chemistry Control Program, that manages loss of material in tanks, components, and piping exposed to an environment of diesel fuel oil by verifying the quality of fuel oil and controlling fuel oil contamination as well as periodic draining, cleaning, and inspection of tanks. This AMP includes surveillance and maintenance procedures to mitigate corrosion of components exposed to a fuel oil environment.

This objective is accomplished by offload sampling and testing of new fuel oil and periodic sampling and chemical analysis of the stored fuel oil. The AMP will also perform periodic draining, cleaning, internal visual inspections, and bottom thickness measurements (via ultrasonic testing) of all in-scope fuel oil tanks, except for the underground fuel tanks (T-175A and T-175B), which will only be drained and inspected if deemed necessary based on the results of fuel oil sample analysis or as recommended by the system engineer.

The PBN Fuel Oil Chemistry AMP includes (a) surveillance and maintenance procedures to mitigate corrosion and (b) measures to verify the effectiveness of the mitigative actions and confirm the insignificance of an aging effect. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the PBN Technical Specifications and Technical Requirements Manual. Guidelines of the American Society for Testing and Materials (ASTM) Standards are also used. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining and/or cleaning of tanks and by verifying the quality of new fuel oil before its introduction into the storage tanks. However, corrosion may occur at locations in which contaminants may accumulate, such as tank bottoms. Accordingly, the effectiveness of the fuel oil chemistry controls is verified to provide reasonable assurance that significant degradation is not occurring. The PBN One-Time Inspection AMP (Section B.2.3.20), the PBN Buried and Underground Piping and Tanks AMP (Section B.2.3.27), the PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP (Section B.2.3.17), and the PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section B.2.3.25) are also used to verify the effectiveness and supplement this AMP.

Components within the scope of the PBN Fuel Oil Chemistry AMP are the diesel fuel oil storage tanks, piping, and other metal components subject to aging management review that are exposed to an environment of diesel fuel oil. The primary tanks within the scope of this AMP are listed below:

- T-030, P-35B Diesel Driven Fire Pump Fuel Oil Day Tank
- T-031A, G-01 Diesel Generator Day Tank
- T-031B, G-02 Diesel Generator Day Tank
- T-032A, Fuel Oil Storage Tank
- T-032B, Fuel Oil Storage Tank
- T-072, Emergency Fuel Oil Storage Tank (buried)
- T-175A, G-01 and G-02 EDG Fuel Oil Storage Tank (underground/within concrete vault)

- T-175B, G-03 and G-04 EDG Fuel Oil Storage Tank (underground/within concrete vault)
- T-176A, G-03 EDG Fuel Oil Day Tank
- T-176B, G-04 EDG Fuel Oil Day Tank
- EDG G-01 and G-02 Skid/Sump (Base)-Mounted Tanks (no equipment tag/ID)
- T-504, Gas Turbine Generator Starting Diesel Engine Fuel Oil Tank
- T-505, G-501 Gas Turbine Generator Auxiliary Power Diesel Engine Fuel Oil Tank

NUREG-2191 Consistency

The PBN Fuel Oil Chemistry AMP, with enhancements, will be consistent with exceptions with the 10 elements of NUREG-2191, Section XI.M30, “Fuel Oil Chemistry.”

Exceptions to NUREG-2191

- PBN does not routinely add corrosion inhibitors, stabilizers, or biocides to the fuel oil. PBN has not experienced oil degradation or microbiologically influenced corrosion (MIC) that indicates the need for these measures. However, corrective actions up to and including fuel oil additives will be used if sample results indicate the presence of these degradation mechanisms.

- The design of the EDG G-01 and G-02 skid tanks does not allow for complete draining, cleaning, 100 percent internal visual inspection, or volumetric inspection of the bottom of the skid tanks. These skid tanks are integral to the baseplate of the diesel engine and generator/pump assembly and are not stand-alone tanks. Accordingly, PBN will take an exception to the cleaning and inspection requirements specified in Element 4 of the GALL-SLR Fuel Oil Chemistry program. As an alternate to the GALL-SLR Element 4 requirements, PBN will drain and clean the G-01 and G-02 EDG skid tanks to the extent practical. Visual inspection of accessible locations of the skid tank internals will be performed and volumetric inspection of accessible portions of the skid tank as close to the bottom of the skid tank as possible will be performed.

- The following underground tanks will only be drained and inspected if deemed necessary based on the results of fuel oil sample analysis or as recommended by the system engineer:

    - T-175A, G-01 and G-02 EDG Fuel Oil Storage Tank
    - T-175B, G-03 and G-04 EDG Fuel Oil Storage Tank

  This exception is justified based on acceptable inspection and wall thickness testing of other fuel oil tanks made of the same material, indicating that no appreciable material loss has occurred in more than 40 years of service as discussed in the OE section. Internal inspection of the buried fuel oil tanks is not required by the plant Technical Specifications. In addition, due to the double wall tank design, regular leak chase monitoring is utilized and such monitoring is capable of identifying any through wall leaks. This leak chase monitoring was used as justification for relief from a similar inspection per Relief from the Requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code for Examination of Buried Components, (Reference ML15127A291). The exterior aging management of these underground tanks is within the scope of the PBN Buried and Underground Piping and Tanks AMP.

- The following tanks have insufficient size and access to facilitate cleaning. Therefore, an exception will be taken to not perform internal cleaning of these tanks:

  - T-030, P-35B Diesel Driven Fire Pump Fuel Oil Day Tank
  - T-176A, G-03 EDG Fuel Oil Day Tank
  - T-176B, G-04 EDG Fuel Oil Day Tank

  Additional actions shall be taken based on visual and volumetric inspection results or when determined necessary by adverse trends or system engineer recommendation.

- The following tanks do not have access locations or are very small (50 gallons), thus making it difficult to perform the required draining, cleaning, and internal inspections. Therefore, 10-year external volumetric inspections of these tanks shall be performed to determine wall thickness in lieu of draining, cleaning, and inspection:

  - T-031A, G-01 Diesel Generator Day Tank
  - T-031B, G-02 Diesel Generator Day Tank
  - T-504, Gas Turbine Generator Starting Diesel Engine Fuel Oil Tank
  - T-505, G-501 Gas Turbine Generator Auxiliary Power Diesel Engine Fuel Oil Tank

Enhancements

The PBN Fuel Oil Chemistry AMP will be enhanced as follows, for alignment with NUREG-2191. This AMP is to be implemented and its inspections and tests begin no earlier than 10 years prior to the SPEO. The inspections and tests are to be completed no later than six months prior to entering the SPEO or no later than the last RFO prior to the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected; 4. Detection of Aging Effects	Update the frequency for T-072 and G-01 skid/sump tanks internal visual inspections preventive maintenance requests (PMRQs) from “on demand” to a 10-year frequency. Clarify that the PMRQs shall include draining and cleaning. See the exception related to the G-01 skid tank inspections.
3. Parameters Monitored or Inspected 4. Detection of Aging Effects	Create a new procedure and/or PMRQ to perform draining and internal visual inspections of the following tanks at least once during the 10-year period prior to the SPEO and repeat the inspection at least once every 10 years: • T-030, P-35B Diesel Driven Fire Pump Fuel Oil Day Tank • T-176A, G-03 EDG Fuel Oil Day Tank • T-176B, G-04 EDG Fuel Oil Day Tank

Element Affected	Enhancement
3. Parameters Monitored or Inspected 4. Detection of Aging Effects	Create new procedures and/or PMRQs to perform volumetric (UT) wall thickness testing, include bottom thickness measurements, of the following tanks: • T-504, Gas Turbine Generator Starting Diesel Engine Fuel Oil Tank • T-505, G-501 Gas Turbine Generator Auxiliary Power Diesel Engine Fuel Oil Tank
3. Parameters Monitored or Inspected 4. Detection of Aging Effects	Update existing PMRQ and model work order to clarify and ensure that the existing volumetric (UT) wall thickness testing will include bottom thickness measurements of the following tanks: • T-030, P-35B Diesel Driven Fire Pump Fuel Oil Day Tank • T-031A, G-01 Diesel Generator Day Tank • T-031B, G-02 Diesel Generator Day Tank • T-072, Emergency Fuel Oil Storage Tank (buried) • T-176A, G-03 EDG Fuel Oil Day Tank • T-176B, G-04 EDG Fuel Oil Day Tank
3. Parameters Monitored or Inspected; 5. Monitoring and Trending	PBN procedures, forms, etc. will be enhanced to: • Perform periodic fuel oil sampling of tanks T-031A and B, T-176A and B, T-504, T-505, and the G-01 and G-02 sump/skid-mounted tanks. Clarify that the sampling specifically monitors the following parameters for trending purposes: water content, sediment content, and total particulate concentration for all in-scope tanks.
4. Detection of Aging Effects	Update procedures, forms, etc. to perform periodic fuel oil sampling of tanks T-031A and B, T-176A and B, T-504, T-505, and the G-01 and G-02 sump/skid-mounted tanks. The sampling methodology shall use either a multilevel sampling technique, such as using an all-level sampling thief or shall obtain a representative sample from the lowest point in the tank if the respective tanks do not allow for multilevel sampling.
5. Monitoring and Trending	All new and existing visual and volumetric inspection procedures for this AMP will include the following monitoring and trending features: • Identified degradation is projected until the next scheduled inspection, where practical. • Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation.
6. Acceptance Criteria	All new and existing visual and volumetric inspection procedures for this AMP will include the following acceptance criteria features: • Any degradation of the tank internal surfaces is reported and is evaluated using the corrective action program. • Thickness measurements of the tank bottom are evaluated against the design thickness and corrosion allowance.
7. Corrective Actions	Update sampling procedures to perform corrective actions to prevent recurrence when the specified limits for fuel oil standards are exceeded or when water is drained during periodic surveillance.
10. Operating Experience	Update sampling procedures to include instructions to provide sampling data to the quarterly fuel oil system health reports.

Operating Experience

Industry Operating Experience

The OE at some nuclear plants has included identification of water in the fuel, particulate contamination, and biological fouling. In addition, when a diesel fuel oil storage tank at one plant was cleaned and visually inspected, the inside of the tank was found to have unacceptable pitting corrosion (> 50 percent of the wall thickness), which was repaired in accordance with American Petroleum Institute (API) 653 standard by welding patch plates over the affected area. To date, the PBN Fuel Oil Chemistry AMP has been effective in preventing unacceptable degradation of the in-scope systems containing fuel oil. Review for recent industry operating experience did not identify any significant experience related to the PBN Fuel Oil Chemistry AMP.

Plant Specific Operating Experience

A recent OE search was performed for SLR which covered a date range of January 1, 2011 through January 1, 2020. This search identified the following action requests (ARs) related to fuel oil systems and/or in-scope tanks:

- In July 2015, external pitting, corrosion, and coating peeling was identified on the exterior of fuel oil piping associated with fuel oil storage tanks T-032A and B. A work request was created to recoat the piping. Although this AR is related to components within the PBN Fuel Oil Chemistry AMP scope, the defect was on the exterior, which is not managed by the PBN Fuel Oil Chemistry AMP but would be managed by the PBN External Surfaces Monitoring of Mechanical Components AMP (Section B.2.3.23).

- In February 2018, during a visual examination the P-035B-E fuel oil lines, the non-destructive examination inspectors identified corrosion where the piping intersects with the floor. Wall loss pits and general areas of corrosion ranged in depth of 0.062 inches to 0.187 inches. The pitting was subsequently repaired under a work order. Although this AR is related to components within this the PBN Fuel Oil Chemistry AMP scope, the defect was on the exterior, which is not managed by the PBN Fuel Oil Chemistry AMP but would be managed by the PBN External Surfaces Monitoring of Mechanical Components AMP (Section B.2.3.23).

- An extensive search of MIC related ARs was conducted, and it was confirmed that none of the MIC-related ARs applied to components within the PBN Fuel Oil Chemistry AMP. This absence can be viewed as demonstrating that the PBN Fuel Oil Chemistry AMP has been successful in managing MIC at PBN.

An effectiveness review of the PBN Fuel Oil Chemistry AMP was performed in 2018 following the guidelines in NEI 14-12. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). The effectiveness review found that implementing documents reference the PBN Fuel Oil Chemistry AMP appropriately. The PBN Fuel Oil

Chemistry AMP was determined to continue to be effectively implemented although the following items were identified:

- Some license renewal credited preventive maintenance tasks were retired without adequate justification.
- The PBN Fuel Oil Chemistry AMP required discussion of the geomembrane liners for tanks T-032A and B that were replaced in 2017. The previous earthen berm surrounding the T-032A and B storage tanks experienced degradation.
- The PBN Fuel Oil Chemistry AMP required an update to state appropriate administrative codes as well as other administrative and editorial changes.

In response to the AMP effectiveness review, an AR was initiated to revise the PBN Fuel Oil Chemistry AMP to include the following changes to resolve the items above:

- Reinstated the preventive maintenance tasks that were retired.
- Made several wording and administrative/editorial changes.

The use of AMP effectiveness self-assessments shows that the PBN Fuel Oil Chemistry AMP is regularly evaluated, which is a trait of a healthy AMP.

Quarterly health reports for the fuel oil system are not reported. However, there are quarterly health reports for the chemistry program and the preventive maintenance program, but these did not appear to have any relevant OE for the time period between January 2015 through February 2020.

In 2010, the NRC performed the 71003 Phase 2 inspection at PBN Unit 1. The inspectors verified that the program and program enhancements for draining water from diesel fuel tanks and periodically taking ultrasonic measurements of day tanks were in place. Additionally, the inspectors confirmed that PBN had implemented a commitment change to replace stability testing with particulate testing for microbiological activity. Based on review of the timeliness and adequacy of the PBN actions, the inspectors determined that the PBN Fuel Oil Chemistry AMP commitments for Unit 1 had been met.

In 2012, the NRC completed the outage segment of the 71003 Phase 1 inspection at PBN Unit 2. This inspection did not focus on the PBN Fuel Oil Chemistry AMP and did not identify any relevant OE for this AMP

In 2013, the NRC performed the 71003 Phase 2 inspection at PBN Unit 2. The inspectors reviewed the licensing basis, program basis document, implementing procedures, chemistry results, and related condition reports (CRs); and interviewed the plant personnel responsible for this program. The inspectors verified the program and program enhancements for draining water from diesel fuel tanks and periodically taking ultrasonic measurements of day tanks were in place. Additionally, the inspectors confirmed that PBN had implemented a commitment change to replace stability testing with particulate testing for microbiological activity. Based on review of the timeliness and adequacy of the PBN actions, the inspectors determined that the PBN Fuel Oil Chemistry AMP commitments for Unit 2 had been met.

In 2019, the NRC performed the 71003 Phase 4 inspections at PBN Units 1 and 2. The PBN Fuel Oil Chemistry AMP was not one of the seven AMPs selected for review.

The previously referenced NRC inspection reports from 2010, 2012, 2013, and 2019 did not identify any elements in the PBN Fuel Oil Chemistry AMP that would require an enhancement for SLR.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Fuel Oil Chemistry AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Fuel Oil Chemistry AMP, with exceptions and enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.19 Reactor Vessel Material Surveillance

Program Description

The PBN Reactor Vessel Material Surveillance AMP is an existing AMP, formerly a portion of the PBN Reactor Vessel Integrity Program. This AMP meets the requirements of 10 CFR Part 50, Appendix H, which requires the implementation of a reactor vessel material surveillance program when the peak neutron fluence at the end of the design life of the vessel exceeds 10^{17} n/cm^2 (E > 1 MeV). The purpose of this AMP is to monitor the changes in fracture toughness to the ferritic reactor vessel beltline materials. As described in Regulatory Issue Summary 2014-11 (Reference ML14149A165), beltline materials are those ferritic reactor vessel materials with a projected neutron fluence greater than 10^{17} n/cm^2 (E > 1 MeV) at the end of the license period (for example, the SPEO), which are evaluated to identify the extent of neutron radiation embrittlement for the material. The surveillance capsules contain reactor vessel material specimens and are located near the inside vessel wall in the beltline region so that the specimens duplicate, as closely as possible, the neutron spectrum, temperature history, and maximum neutron fluence experienced at the inner surface of the reactor vessel. Because of the location of the capsules between the reactor core and the reactor vessel wall, surveillance capsules typically receive neutron fluence exposures that are higher than the inner surface of the reactor vessel. This allows surveillance capsules to be withdrawn and tested prior to the inner surface receiving an equivalent neutron fluence so that the surveillance test results bound the conditions at the end of the SPEO.

This AMP addresses neutron embrittlement of all ferritic reactor vessel beltline materials as defined by 10 CFR Part 50, Appendix G, at the region of the reactor vessel that directly surrounds the effective height of the active core and the adjacent regions of the reactor vessel that are predicted to experience sufficient neutron damage to be considered in the selection of the limiting material with regard to radiation damage. Materials with a projected neutron fluence greater than 10^{17} n/cm^2 (E > 1 MeV) at the end of the SPEO are considered to experience sufficient neutron damage to be included in the beltline. Materials monitored within the PBN license renewal materials surveillance program continue to serve as the basis for this AMP.

The surveillance portion of this AMP adheres to the requirements of 10 CFR Part 50, Appendix H as well as the ASTM standards incorporated by reference in 10 CFR Part 50, Appendix H. The surveillance capsule withdrawal schedule is documented in TRM 2.2. Surveillance capsules are designed and located to permit insertion of replacement capsules.

This program includes withdrawal and testing of the Supplemental “A” surveillance capsule. This capsule will receive between one to two times the peak reactor vessel neutron fluence of interest at the end of the SPEO in the TLAAs for USE, PTS, and P-T limits.

PBN was a member of the Babcock & Wilcox Owners Group (B&WOG) reactor vessel working group. The B&WOG designed an irradiation surveillance program (Master Integrated Reactor Vessel Program, MIRVP) (Reference ML021200080) in which member materials are irradiated at host plants. The MIRVP Charpy values and direct fracture toughness (master curve) data will be used as supplemental data. The PWROG is now the mechanism for the previous B&WOG reactor vessel working group activities, and PBN is a member of the PWROG. The implementation of the MIRVP in this Reactor Vessel Material Surveillance AMP is only for supplemental data and is not a part of the NRC-approved surveillance program. This AMP relies fully on onsite capsules.

The objective of the PBN Reactor Vessel Material Surveillance AMP is to provide sufficient material data and dosimetry to (a) monitor IE to a neutron fluence level which is greater than the projected peak neutron fluence of interest projected to the end of the SPEO, and (b) provide adequate dosimetry monitoring during the SPEO. Dosimetry monitoring during the SPEO is performed by the PBN Neutron Fluence Monitoring AMP (Section B.2.2.2). The PBN Reactor Vessel Material Surveillance AMP provides data on neutron embrittlement of the reactor vessel materials and neutron fluence data. These data are used to evaluate the TLAAs on neutron IE (e.g., USE, PTS, P-T limits evaluations, etc.) as needed to demonstrate compliance with the requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.61 for the SPEO, as described in NUREG-2192, Section 4.2. This AMP has one capsule that will attain neutron fluence between one and two times the peak reactor vessel wall neutron fluence of interest at the end of the SPEO. The AMP withdraws, and subsequently tests, the capsule at an outage in which the capsule receives a neutron fluence of between one and two times the peak reactor vessel neutron fluence of interest at the end of the SPEO. Test results from this capsule are reported, consistent with 10 CFR Part 50, Appendix H.

All withdrawn surveillance capsules not discarded as of August 31, 2000, are placed in storage, for the purposes of future reconstitution and use, if necessary. All capsules placed in storage must be maintained for future insertion. Any changes to storage requirements must be approved by the NRC, as required by 10 CFR 50, Appendix H.

This PBN Reactor Vessel Material Surveillance AMP is a condition monitoring program that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in the Upper Shelf Energy (USE) as a function of neutron fluence and irradiation temperature. The data from this surveillance program are used to monitor neutron irradiation embrittlement of the reactor vessel and are inputs to the neutron embrittlement TLAAs. The PBN Reactor Vessel Material Surveillance AMP is also used in conjunction with the proposed PBN Neutron Fluence Monitoring AMP (Section B.2.2.2).

All surveillance capsules, including those previously withdrawn from the reactor vessel, must meet the test procedures and reporting requirements of the applicable ASTM standards referenced in 10 CFR Part 50, Appendix H, to the extent practicable, for the configuration of the specimens in the capsule. Any changes to the surveillance capsule withdrawal schedule must be approved by the NRC prior to implementation, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3.

NUREG-2191 Consistency

The PBN Reactor Vessel Material Surveillance AMP will be consistent, with exception, with the 10 elements of NUREG-2191, Section XI.M31, “Reactor Vessel Material Surveillance.”

Exceptions to NUREG-2191

The “A” capsule was originally intended to address the initial period of extended operation. As such, the PBN XI.M31 AMP will take the following exception to the NUREG-2191 Section XI.M31 AMP elements 3 and 5:

- In order to achieve the peak 72 EFPY end-of-life fluence values identified in the reactor vessel embrittlement TLAAs for USE, PTS, ART and P-T limits presented in SLRA Section 4.2, an incremental adjustment to the approved capsule withdrawal schedule for the “A” capsule is requested. The PBN standby capsules (“N” in both Units 1 and 2) do not contain the most limiting material and there are no plans to withdraw these capsules. The current approved withdrawal of capsule “A” is scheduled for Fall of 2024 at a fluence of 5.07×10^{19} n/cm^2, for the 60-year license renewal period.

- Using the 72 EFPY bounding fluence projections identified in the reactor vessel embrittlement TLAAs presented in SLRA Section 4.2, PBN capsule “A” can achieve a fluence of at least 8.07×10^{19} n/cm^2 at 51 EFPY, which bounds the 72 EFPY projected fluence for the limiting PBN Unit 1 axial weld and plate material and PBN Units 1 and 2 circumferential welds. This incremental change to the capsule “A” withdrawal schedule will allow sufficient material data and dosimetry to be obtained to monitor irradiation embrittlement through the end of the SPEO. Further, the test data from capsule “A” will be available for removal and testing in Spring 2035, based on the current operating schedule, which corresponds to > 51 EFPY.

  In accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3, approval is requested to extend the Point Beach capsule A withdraw schedule from 43 EFPY to the first refueling outage that meets or exceeds (≥) 51 EFPY with a projected fluence of 8.07×10^{19} n/cm^2 to bound the 80 year (72 EFPY) projected end of the SPEO fluence for the Point Beach Units 1 and 2 reactor vessels. The proposed change to the surveillance capsule withdraw schedule from the Point Beach Units 1 and 2 Technical Requirements Manual (TRM) Section 2.2, Table 1, is provided in Appendix A with revisions indicated by text deletion (strikethrough) and text addition (double underlined).

Enhancements

None.

Operating Experience

Industry Operating Experience

Industry operating experience related to the PBN Reactor Vessel Material Surveillance AMP includes GL 92-01, Revision 1, "Reactor Vessel Structural Integrity," and Supplement 1 to GL 92-01, Revision 1, "Reactor Vessel Structural Integrity." PBN's response to these documents has been incorporated into the PBN Reactor Vessel Material Surveillance AMP.

A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the PBN Reactor Vessel Material Surveillance AMP.

Plant Specific Operating Experience

The PBN Reactor Vessel Material Surveillance AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

To date, no enhancements to the AMP have been identified as a result of operating experience. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Reactor Vessel Material Surveillance AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Reactor Vessel Material Surveillance AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.20 One-Time Inspection

Program Description

The PBN One-Time Inspection AMP is an existing AMP, previously known as the One-Time Inspection Program, that consists of a one-time inspection of selected components to verify: (a) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the SPEO; (b) the insignificance of an aging effect; and (c) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

The elements of the program include: (a) determination of the sample size of components to be inspected 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 potential for the aging effect to occur, (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) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the SPEO. The inspection sample includes locations where the most severe aging effect(s) would be expected to occur. Inspection methods may include visual (or remote visual), surface or volumetric examinations, or other established NDE techniques.

The inspection includes a representative sample of each population (defined as components having the same material, environment, and aging effect combination) and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. A representative sample size is 20 percent of the population or a maximum of 25 components at each unit. Otherwise, a technical justification of the methodology and sample size used for selecting components for one-time inspection is included as part of the program documentation. Factors that will be considered when choosing components for inspection are time in service, severity of operating conditions, and OE.

The PBN One-Time Inspection AMP will also perform inspections on the Unit 1 steam generator divider plate assemblies and the steam generator circumferential transition cone field welds on both units in order to verify the effectiveness of the PBN Water Chemistry AMP (Section B.2.3.2). The one-time volumetric inspection on each steam generator transition cone field weld is intended to cover essentially 100 percent of the total weld length. The inspections on each Unit 1 steam generator divider plate assembly will be capable of detecting primary water stress corrosion cracking in the divider plate assemblies and associated welds.

The program is used to verify the effectiveness of the PBN Water Chemistry (Section B.2.3.2), Fuel Oil Chemistry (Section B.2.3.18), and Lubricating Oil Analysis (Section B.2.3.26) AMPs. For steel components exposed to water environments that do not include corrosion inhibitors as a preventive action (e.g., treated water, treated borated water, raw water, waste water), the program is used to verify that long-term loss of material due to general corrosion will not cause a loss of intended function [e.g., pressure boundary, leakage boundary (spatial), structural integrity (attached)].

The program is not used for structures or components with known age-related degradation mechanisms or when the environment in the SPEO is not expected to be equivalent to that in the prior operating period. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

The PBN One-Time Inspection AMP is a condition monitoring program that does not include methods to mitigate or prevent age-related degradation. The PBN One-Time Inspection AMP monitors the parameters and related aging effects provided in NUREG-2191, Table XI.M32-1.

The acceptance criteria for this program considers both the results of observed degradation during current inspections and the results of projecting observed degradation of the inspections for each material, environment and aging effect combinations. Acceptance criteria are based on applicable ASME Code or other appropriate standards, design basis information, or vendor-specified requirements and recommendations (e.g., ultrasonic thickness measurements are compared to predetermined limits); however, crack-like indications are not acceptable. Where it is practical to project observed degradation to the end of the SPEO, the projected degradation will not: (a) affect the intended function of a system, structure, or component; (b) result in a potential leak; or (c) result in heat transfer rates below that required by the CLB to meet design limits. Where measurable degradation has occurred, but acceptance criteria have been met, the inspection results are entered into the corrective action program for future monitoring and trending.

The PBN One-Time Inspection AMP implementation, enhancements, and pre-SPEO inspections will be completed no later than 6 months prior to the SPEO or no later than the last refueling outage prior to the SPEO. The pre-SPEO inspections will start no earlier than 10 years prior to the SPEO.

NUREG-2191 Consistency

The PBN One-Time Inspection AMP, with enhancements, will be consistent with the ten elements of NUREG-2191, Section XI.M32, “One-Time Inspection”.

Exceptions to NUREG-2191

None.

Enhancements

The PBN One-Time Inspection AMP will be enhanced as follows, for alignment with NUREG-2191, Section XI.M32. The PBN One-Time Inspection AMP implementation, enhancements, and pre-SPEO inspections will be completed no later than 6 months prior to the SPEO or no later than the last refueling outage prior to the SPEO. The pre-SPEO inspections will start no earlier than 10 years prior to the SPEO.

Element Affected	Enhancement
1. Scope of Program	• Include verification of the effectiveness of the PBN Lubricating Oil Analysis AMP for managing the effects of aging of various components in systems containing lubricating oil. • For steel components exposed to water environments that do not include corrosion inhibitors as a preventive action (e.g., treated water, treated borated water, raw water, waste water), include verification that long-term loss of material due to general corrosion will not cause a loss of intended function [e.g., pressure boundary, leakage boundary (spatial), structural integrity (attached)]. Long-term loss of material due to general corrosion for steel components need not be managed if one of the following two conditions is met: (i) the environment for the steel components includes corrosion inhibitors as a preventive action; or (ii) wall thickness measurements on a representative sample of each environment will be conducted between the 50th and 60th year of operation. • Perform one-time volumetric inspections on each of the steam generator transition cone field welds on both units. This one-time volumetric inspection on each steam generator transition cone field weld is intended to cover essentially 100% of the total weld length. • Perform one-time inspections of the Unit 1 steam generator divider plate assemblies. The inspections will be capable of detecting primary water stress corrosion cracking in the divider plate assemblies and associated welds.
3. Parameters Monitored or Inspected	• For verification of the effectiveness of the PBN Lubricating Oil Analysis AMP, a visual examination or other appropriate NDE methodology will be used to verify that degradation due to the applicable aging effects is not occurring.
4. Detection of Aging Effects	• The inspection includes a representative sample of each population (defined as components having the same material, environment, and aging effect combination) and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. A representative sample size is 20 percent of the population or a maximum of 25 components at each unit. Otherwise, a technical justification of the methodology and sample size used for selecting components for one-time inspection is included as part of the program documentation. Factors that will be considered when choosing components for inspection are time in service, severity of operating conditions, and OE.
5. Monitoring and Trending	• Inspection results for each material, environment, and aging effect are compared to those obtained during previous inspections, when available. Where practical, these results are trended in order to project observed degradation to the end of the SPEO.

Element Affected	Enhancement
6. Acceptance Criteria	• The acceptance criteria for this program considers both the results of observed degradation during current inspections and the results of projecting observed degradation of the inspections for each material, environment and aging effect combinations. • Acceptance criteria may be based on applicable ASME Code or other appropriate standards, design basis information, or vendor-specified requirements and recommendations (e.g., ultrasonic thickness measurements are compared to predetermined limits); however, crack-like indications are not acceptable. • Where it is practical to project observed degradation to the end of the SPEO, the projected degradation will not: (a) affect the intended function of a system, structure, or component; (b) result in a potential leak; or (c) result in heat transfer rates below that required by the CLB to meet design limits. • Where measurable degradation has occurred, but acceptance criteria have been met, the inspection results are entered into the corrective action program for future monitoring and trending.
7. Corrective Actions	• If the cause of the aging effect for each applicable material and environment is not corrected by repair of replacement for all components constructed of the same material and exposed to the same environment, additional inspections are conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections is determined in accordance with the corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections. Because PBN is a multi-unit site, the additional inspections include inspections at both units with the same material, environment, and aging effect combination. • Where an aging effect identified during an inspection does not meet acceptance criteria or projected results of the inspections of a material, environment, and aging effect combination do not meet the above acceptance criteria, a periodic inspection program is developed for the specific material, environment, and aging effect combination. The periodic inspection program is implemented at both units with same combination(s) of material, environment, and aging effect.

Operating Experience

Industry Operating Experience

The elements that comprise inspections associated with this program (the scope of the inspections and inspection techniques) are consistent with industry practice. OE with detection of aging effects should be adequate to demonstrate that the program is capable of detecting the presence or noting the absence of aging effects in the components, materials, and environments where one-time inspection is used to confirm system-wide effectiveness of another preventive or mitigative AMP.

Recent industry operating experience was reviewed from the SLR Safety Evaluation Reports for the first three submitted SLRAs (Turkey Point, Peach Bottom, and Surry). Two main points of interest are ensuring that the One-Time Inspection AMP is not used for managing aging of systems or components with known age-related degradation issues and ensuring that one-time inspections are completed on steam generator components, as necessary. The steam generator inspection locations of interest for the One-Time Inspection AMP are the divider plate assemblies and any circumferential transition cone welds (if replacement activities resulted in a circumferential field weld).

Plant Specific Operating Experience

Inspections Performed Prior to the PEO for First License Renewal

- A total of 174 one-time inspections were completed prior to the PEO, not including additional inspections performed due to scope expansions. Operating experience related to scope expansions initiated due to inspection findings is provided below.
    - The stainless steel in borated primary water <140°F group included a scope expansion due to erosion/cavitation damage found in the flange area immediately downstream of a valve used for throttling. While not an applicable aging effect (improper design/use of system), similar erosion was found on the same valve for the opposite unit. Preventive maintenance activities were generated to periodically inspect these locations.
    - The carbon/low alloy steel in treated secondary water >120°F group included a scope expansion to inspect a valve when some minor erosion was found in the adjacent piping. The piping was conservatively replaced and added to the FAC program for ongoing aging management.
    - The carbon/low alloy steel in air/gas wetted group included a scope expansion to inspect the component cooling water surge tanks after an initial inspection found recordable indications on adjacent carbon steel piping to these tanks. Ultrasonic testing (UT) to confirm wall thickness was performed on both tanks, with both results indicating wall thicknesses above nominal and substantially above minimum wall thickness.
    - Eddy current testing of the Unit 1 “A” RHR heat exchanger tubing included a scope expansion to include the Unit 1 “B” heat exchanger. The inspection identified some tube fretting in the same area as the “A” heat exchanger. Corrective actions were initiated from the apparent cause review, which included inspection of the Unit 2 RHR heat

exchangers. Tube fretting was not identified on the Unit 2 RHR heat exchangers; however, some minor degradation was found which resulted in 5 tubes being conservatively plugged. Preventive maintenance activities were generated to inspect the Unit 1 RHR heat exchangers every 6 years and the Unit 2 RHR heat exchangers every 15 years.

System/Program Health Reports

- The Chemistry Program health report is currently green. Historically speaking, the Chemistry Program has been green since 2015, with a few exceptions for white in 2015 through 2017.

- Fuel Oil System health reports and Lubricating Oil System health reports do not provide any information relevant to aging management and the One-Time Inspection Program.

Program Assessments and Evaluations

- June 2010 Phase 2 License Renewal Self-Assessment

  - Self-assessment recommended a revision to the One-Time Inspection AMP regarding acceptance criteria and inspector qualifications. Acceptance Criteria were modified to include further evaluation through the corrective action program when recordable indications do not meet the initial acceptance criteria. The One-Time Inspection AMP was also modified to include statements that NDE exams are conducted with the requirements of ASME Code Section XI and 10 CFR 50, Appendix B. Fouling exams use ASME Code Section V and 10 CFR 50, Appendix B.

  - Self-assessment identified that a gas turbine generator starting diesel engine fuel oil tank was examined via UT in 2009, but there was no overall evaluation of the acceptability of the data. Subsequently, an evaluation of the acceptability of the results was completed, and the tank was re-inspected in both 2012 and 2018. The inspection results demonstrated that there are no active degradation mechanisms occurring inside the tank that could threaten the intended function of the tank through the period of extended operation.

  - Self-assessment identified that there was inadequate technical rigor applied to some evaluations of degradation recorded during one-time inspections. Some follow-up actions were also cancelled or deferred over a period of several years. Work requests were completed for the follow-on exams, and the results and dispositions were included in the One-Time Inspection AMP documentation.

NRC Inspections

- March 2010 IP 71003 Phase I Inspection, Unit 1 – ML101200365

  NRC inspectors interviewed the program owner, reviewed implementing procedures and records of completed inspections, and performed direct observation of NDE examinations in the field. Commitments associated with the One-Time Inspection Program were also reviewed. The Phase I inspectors determined that the inspection selection methodology provides generic guidance for picking the individual components to inspect, but it does not provide an overall justification for ensuring that the most susceptible environments have been tested with the selected samples. As a result, PBN revised the inspection selection methodology prior to the Phase II inspection, in order to provide documentation that the samples selected provide reasonable assurance that the areas most susceptible to aging effects were actually inspected.

- August 2010 IP 71003 Phase II Inspection, Unit 1 – ML102850469

  NRC inspectors reviewed the licensing basis, program basis document, sampling methodology, completed work orders, and related CRs; and interviewed the plant personnel responsible for the One-Time Inspection program. The inspectors verified that selective leaching inspections and eddy current testing of the 1A RHR HX had been incorporated in the program and completed. The inspectors determined PBN met the commitment items associated with the One-Time Inspection program.

- November 2012 IP 71003 Phase I Inspection, Unit 2 – ML12355A774

  NRC inspectors reviewed the documented results of eddy current inspections of the U2 RHR HX tubes and visual inspections. The inspectors had no concerns with the observed activities.

- February 2013 IP 71003 Phase II Inspection, Unit 2 – ML13077A472

  NRC inspectors reviewed the licensing basis, program basis document, sampling methodology, completed work orders, and related CRs; and interviewed the plant personnel responsible for the One-Time Inspection program. The inspectors verified the selective leaching inspections and eddy current testing of the 2A RHR HX had been incorporated in the program and completed. The inspectors determined PBN met the commitment items associated with the One-Time Inspection program.

- AMP Effectiveness Reviews

  PBN completed License Renewal Aging Management Program Effectiveness Reviews in 2018. The One-Time Inspection Program was not part of this AMP effectiveness review because the program does not include on-going aging management activities and is therefore considered complete. The original One-Time Inspection Program verified the effectiveness of the Water Chemistry (Section B.2.3.2), Closed Cycle Cooling Water (Section B.2.3.12), and Fuel Oil Chemistry AMPs (Section B.2.3.18), and therefore the results of those effectiveness reviews will be considered.

- The Water Chemistry AMP did not have any identified gaps. Procedure changes were initiated to update the AMP.
- The Closed Cycle Cooling Water AMP did not have any identified gaps. Procedure changes were initiated to update the AMP.
- The Fuel Oil Chemistry AMP had several credited preventive maintenance tasks being retired, potentially without adequate justification. As a corrective action, the preventive maintenance requirements were reinstated.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN One-Time Inspection AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN One-Time Inspection AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.21 Selective Leaching

Program Description

The PBN Selective Leaching AMP is a new AMP that has the principal objective to manage the aging effect of loss of material due to selective leaching.

The PBN Selective Leaching AMP includes inspections of components made of gray cast iron, ductile iron, and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc or greater than 8 percent aluminum exposed to a raw water, closed-cycle cooling water, treated water, waste water, or soil environment. For closed-cycle cooling water and treated water environments, the AMP includes one-time visual inspections of selected components that are susceptible to selective leaching, coupled with mechanical examination techniques (e.g., chipping, scraping). For raw water, waste water, and soil environments, the AMP includes opportunistic and periodic visual inspections of selected components that are susceptible to selective leaching, coupled with mechanical examination techniques. Destructive examinations of components to determine the presence of and depth of dealloying through-wall thickness are also conducted. These techniques can determine whether loss of material due to selective leaching is occurring and whether selective leaching will affect the ability of the components to perform their intended function for the SPEO.

Each of the one-time and periodic inspections for the various material and environment populations at each unit comprises a 3 percent sample or a maximum of 10 components. For each material and environment population with 35 or more susceptible components, two destructive examinations will be performed in each 10-year inspection interval at each unit. For each material and environment population with less than 35 susceptible components, one destructive examination will be performed in each 10-year inspection interval at each unit.

The selective leaching process involves the preferential removal of one of the alloying components from the material. Dezincification (loss of zinc from brass) and graphitization or graphitic corrosion (removal of iron from gray cast iron and ductile iron) are examples of such a process. Susceptible materials exposed to high operating temperatures, stagnant-flow conditions, and a corrosive environment (e.g., acidic solutions for brasses with high zinc content and dissolved oxygen) are conducive to selective leaching. A dealloyed component often retains its shape and may appear to be unaffected; however, the functional cross-section of the material has been reduced. The aging effect attributed to selective leaching is loss of material because the affected volume has a permanent change in density and does not retain mechanical properties that can be credited for structural integrity.

The inspection acceptance criteria are as follows:

a. For copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color or green copper oxide.
b. For gray cast iron and ductile iron, the absence of a surface layer that can be easily removed by chipping or scraping or identified in the destructive examinations.

c. The presence of no more than a superficial layer of dealloying, as determined by removal of the dealloyed material by mechanical removal.
d. The components meet system design requirements such as minimum wall thickness, when extended to the end of the SPEO.

When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the SPEO, additional inspections are performed if the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of additional inspections is equal to the number of failed inspections for each material and environment population, with a minimum of five additional visual and mechanical inspections when visual and mechanical inspections did not meet acceptance criteria, or 20 percent of each applicable material and environment combination is inspected, whichever is less, and a minimum of one additional destructive examination when destruction examination(s) did not meet acceptance criteria.

If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, in all cases, the additional inspections are completed within the interval in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next RFO interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. Since PBN is a multi-unit site, the additional inspections include inspections at both Units 1 and 2 when the two units have the same material, environment, and aging effect combination.

The PBN Selective Leaching AMP will have a new governing and inspection procedure consistent with NUREG-2191, Section XI.M33.

The PBN Selective Leaching AMP implementation and pre-SPEO inspections will be completed no later than 6 months prior to the SPEO or no later than the last refueling outage prior to the SPEO. The pre-SPEO inspections will start no earlier than 10 years prior to the SPEO.

NUREG-2191 Consistency

The PBN Selective Leaching AMP will be consistent with the ten elements of NUREG-2191, Section XI.M33, “Selective Leaching”.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

- OE shows that selective leaching has been detected in components constructed from gray cast iron, ductile iron, brass, bronze, and aluminum bronze. The following OE from NUREG-2191 Section XI.M33 is relevant to PBN:

    - During a one-time inspection for selective leaching, a licensee identified degradation in four gray cast iron valve bodies in the service water system exposed to raw water. The mechanical test used by the licensee to identify the graphitization was tapping and scraping of the surface. The licensee sand blasted two of the valve bodies and, after all of the graphite was removed; the licensee determined that the leaching progressed to a depth of approximately 3/32 inch. Based on the estimated corrosion rate, the licensee determined that the valve bodies had adequate wall thickness for at least 20 years of additional service. (Reference ML14017A289).

    - Based on visual inspections conducted as part of implementing a one-time inspection for selective leaching, a licensee identified selective leaching in a gray cast iron drain plug of an auxiliary feedwater pump outboard bearing cooler. Possible selective leaching was also found on multimatic valves on the underside of the clapper. As a result, the licensee incorporated quarterly inspections of the components in its periodic surveillance and preventive maintenance program. (Reference ML13122A009).

    - A licensee has reported occurrences of selective leaching of aluminum bronze components for an extensive number of years. (Reference ML17142A263).

    - NRC IN 94-59, Accelerated Dealloying of Cast Aluminum-Bronze Valves Caused by Microbiologically Induced Corrosion, August 17, 1994.

    - The basis for inclusion of ductile iron in this GALL-SLR Report AMP XI.M33, along with OE examples, is cited in the GALL-SLR and SRP-SLR Supplemental Staff Guidance document. (Reference ML16041A090).

- Recent industry OE was reviewed from the SLR Safety Evaluation Reports for the first three submitted SLRAs (Turkey Point, Peach Bottom, and Surry).

    - Based on plant operating experience, the Selective Leaching AMP needs to ensure that one-time inspections are not selected when there are known issues with selective leaching in treated water or closed cycle cooling water environments. In addition, if plant operating experience demonstrates significant issues with selective leaching, further inspections and exploratory work may be required to adequately manage selective leaching.

- The Selective Leaching AMP needs to ensure that a process exists to evaluate difficult-to-access surfaces if unacceptable inspection findings occur within the same material and environment population.

Plant Specific Operating Experience

- In July 2010, selective leaching was identified in a solenoid valve constructed of Cu >15% Zn in raw water. The valve was destructively tested and evidence of dezincification (selective leaching) in the valve body and the valve bonnet was found. Corrective actions were initiated which required a scope expansion to remove a similar valve for testing. Destructive testing was completed on the valve, which confirmed the valve was the same material (Cu >15% Zn) and did not have any evidence of selective leaching.

- In June 2010, PBN evaluated industry operating experience from Monticello, which indicated that selective leaching had been found in components constructed of cast iron in raw water. At the time, PBN had completed one-time visual inspections of components within this material and environment group, which revealed no evidence of selective leaching. Based on this OE from Monticello, PBN destructively tested additional cast iron in raw water components to validate the results of the visual inspections. Two valves were selected and destructively tested, which revealed no evidence of selective leaching. These destructive testing results confirmed the visual inspections which found no evidence of selective leaching in components constructed of cast iron in raw water.

- In 2009 and 2010, 13 one-time inspections were completed on cast iron components and copper alloy >15% Zn components in various treated water environments. Three of these components (all were cast iron in treated water – secondary) were destructively tested, and no evidence of selective leaching was found. The remaining 10 components were visually and mechanically examined and found no evidence of selective leaching in any of the treated water environments. In addition, an AR review for the 2010 through 2019 timeframe found no evidence of selective leaching in components exposed to treated water or closed cycle cooling water environments.

- NRC Inspections

  - August 2010 IP 71003 Phase II Inspection, Unit 1 – (Reference ML102850469)

    NRC inspectors reviewed the licensing basis, program basis document, sampling methodology, completed work orders, and related CRs; and interviewed the plant personnel responsible for the One-Time Inspection program. The inspectors verified that selective leaching inspections had been incorporated in the program and completed.

- February 2013 IP 71003 Phase II Inspection, Unit 2 – (Reference ML13077A472)

  NRC inspectors reviewed the licensing basis, program basis document, sampling methodology, completed work orders, and related CRs; and interviewed the plant personnel responsible for the One-Time Inspection program. The inspectors verified the selective leaching inspections had been incorporated in the program and completed.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Selective Leaching AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Selective Leaching AMP will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.22 ASME Code Class 1 Small-Bore Piping

Program Description

The PBN ASME Code Class 1 Small-Bore Piping AMP is an existing condition monitoring program for detecting cracking in small-bore, ASME Code Class 1 piping. This AMP augments the ISI program specified by ASME Code, Section XI, Sections IWB, IWC, and IWD (Section B.2.3.1), for certain ASME Code Class 1 piping that is less than 4 inches nominal pipe size (NPS) and greater than or equal to 1 inch NPS, and manages the effects of SCC and cracking due to thermal or vibratory fatigue loading. This AMP inspects ASME Code Class 1 small-bore piping locations that are susceptible to cracking and inspects full penetration (butt) and partial penetration (socket) welds. This AMP also includes measures to verify that degradation is not occurring, thereby confirming that there is no need to manage age-related degradation.

Industry OE demonstrates that welds in ASME Code Class 1 small-bore piping are susceptible to SCC and cracking due to thermal or vibratory fatigue loading. Such cracking is frequently initiated from the inside diameter of the piping; therefore, volumetric examinations are needed to detect cracks. However, ASME Code, Section XI, generally does not call for volumetric examinations of this class and size of piping. Therefore, this AMP supplements the ASME Code Section XI examinations with volumetric examinations, or alternatively, destructive examinations, to detect cracks that may originate from the inside diameter of butt welds, socket welds, and their base metal materials. The examination schedule and extent are based on site-specific OE and whether actions have been implemented that would successfully mitigate the causes of any past cracking.

A one-time inspection to detect cracking in welds and base metal materials will be performed by either volumetric or destructive examination. These inspections will provide assurance that aging-related cracking of small-bore ASME Code Class 1 piping is not occurring or is insignificant. Volumetric examinations will be performed on selected full penetration butt welds. Volumetric examination will be performed using demonstrated techniques from the ASME Code that are capable of detecting the aging effects in the examination volume of interest.

Socket welds may be inspected via volumetric or destructive examination. Because more information can be obtained from a destructive examination than from nondestructive examination, credit will be taken for each weld destructively examined equivalent to having volumetrically examined two welds.

Per NUREG-2191, Table XI.M35-1, PBN is a Category A plant because it has no history of age-related cracking. Per Category A, the inspection will be a one-time inspection with a sample size of at least 3 percent, up to a maximum of 10 welds, of each weld type, for each operating unit using a methodology to select the most susceptible and risk-significant welds.

Table B-6
PBN Unit 1 Welds

Weld Type	Total Number	3%	Sample Size (Max 10 Welds Each Type)
Socket	438	14	10
Full Penetration Butt	131	4	4

Table B-7
PBN Unit 2 Welds

Weld Type	Total Number	3%	Sample Size (Max 10 Welds Each Type)
Socket	316	10	10
Full Penetration Butt	121	4	4

Based on the results of these inspections, the need for additional inspections or programmatic corrective actions will be established. Should evidence of cracking be revealed by the one-time inspections, a periodic inspection plan will be implemented in accordance with NUREG-2191, Table XI.M35-1.

If a component containing flaws or relevant conditions is accepted for continued service by analytical evaluation, then it is subsequently reexamined to meet the intent of ASME Code, Section XI, Sub-article IWB-2420. Examination results are evaluated in accordance ASME Code, Section XI, Paragraph IWB-3132. The corrective actions include examinations of additional ASME Code Class 1 small-bore piping welds to meet the intent of ASME Code, Section XI, Subarticle IWB-2430. Additionally, periodic examinations are implemented in accordance with the schedule specified in Category C.

NUREG-2191 Consistency

The PBN ASME Code Class 1 Small-Bore Piping AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M35, "ASME Code Class 1 Small-Bore Piping."

Exceptions to NUREG-2191

None.

Enhancements

The PBN ASME Code Class 1 Small-Bore Piping AMP will be enhanced as follows, for alignment with NUREG-2191. This AMP is to be implemented and its inspections are to be completed no earlier than six years prior to the SPEO and no later than six months prior to the SPEO, or no later than the last RFO prior to the SPEO.

Element Affected	Enhancement
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria 7. Corrective Actions	Create a new procedure to do the following: • Perform the new one-time inspections of small-bore piping using the program methods, frequencies, and acceptance criteria included in a new program procedure. • Evaluate the results to determine if additional or periodic examinations are required. • Perform any required additional inspections.

Operating Experience

Industry Operating Experience

PBN evaluates industry OE items for applicability per the NextEra Fleet OE Program and takes corrective actions, when necessary. For example:

- Turkey Point Nuclear Generating Station (PTN): In July of 2012, a post-approval license renewal inspection was performed by NRC prior to the period of extended operation. No findings were identified from the inspection; however, one observation was noted which identified a potential inadequacy regarding the small-bore Class 1 piping inspection sample scope for Unit 3. The inspectors were concerned that the single location of similar weld types selected for destructive examination did not constitute a representative sample on which to base a determination that no aging effects were present. The observation was captured in the corrective action program (CAP) and for the scope of the subsequent Unit 4 inspections, the samples chosen were all from different welds that were exposed to various pressure-temperature environments and consistent with the intent of the program. No additional actions were deemed necessary.

- Surry Power Station (SPS): In April 2015, after reviewing a Root Cause Evaluation from North Anna Power Station regarding leakage from a reactor coolant system loop drain line, SPS committed to inspect the two inch hot and cold leg drain lines on the three reactor coolant system loops, using EPRI MRP-146, “Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines”. The volumetric inspections of the drain lines identified three crack-like indications in the ‘B’ loop cold leg drain. The three indications were axial in orientation, in the base metal, and located in the horizontal section of piping between the first elbow and the downstream valve. There was no evidence of any leakage at the three locations in the ‘B’ loop cold leg drain. The section of piping with the indications was removed for destructive examination and was replaced satisfactorily. Volumetric examinations were performed on the other two cold leg drain lines and on the three hot leg drain lines. No indications were identified.

The results of the destructive examination for the cold leg drain pipe concluded that the crack-like indications were defects associated with tearing or deformation of the inner surface that occurred during fabrication. The cracks were not induced by thermal fatigue.

- Peach Bottom Atomic Power Station (PBAPS): One Class 1 small-bore piping crack and leak at a socket weld on Unit 3 in 2005 (LER 03-05-03), and another Class 1 small-bore piping crack and leak at a socket weld on Unit 3 in 2017 (LER 3-17-001). There have been no other Class 1 small-bore piping cracking or leak issues during the Unit 3 operating history. There have been no Class 1 small-bore piping cracking or leak issues during the Unit 2 operating history.

Since any cracking or leakage from Class 1 reactor coolant pressure boundary components would be required to be reported to the NRC per 10 CFR 50.73(a)(2), a review of all License Event Reports (LERs) was performed using keyword searches (crack and Class 1). The review identified 30 LERs, 4 of which were actually related to Class 1 small-bore piping from the past 20 years.

Four of the five (Hatch – LER 2-2008-003-1, Calhoun – LER 2015-005, Turkey Point – LER 2008-003-00, and St. Lucie – LER 2017-001-1) were due to cyclic fatigue, which resulted in:

- Hatch: Systems within the ASME Class 1 boundary were reviewed for lines which are small-bore, not isolable, and stainless steel. Sixteen main steam flow connections on each unit and the four flow measurement lines were selected to be evaluated and corrective actions taken as determined appropriate.
- Calhoun: A design modification of reactor coolant pump seal package piping.
- Turkey Point: Repair of a reactor coolant pump test connection line.
- St. Lucie: Repair of a reactor coolant pump lower seal heat exchanger.

One (Palisades – LER 2000-004) was due to inadequate post-weld treatment.

Additionally, one of the PBN commitments in the Safety Evaluation Report related to the License Renewal of the Point Beach Nuclear Plant (NUREG-1839) requires monitoring of on-going industry activities related to failure mechanisms for small-bore piping and to evaluate changes to PBN inspection activities based on industry recommendations.

The examples above demonstrate that the PBN ISI AMP reviews OE and incorporates applicable industry OE into the program. This ensures that the PBN ASME Code Class 1 Small-Bore Piping AMP will continue to be effective during the SPEO.

<u>Plant Specific Operating Experience:</u>

The site-specific OE for ASME Code Class 1 Small-bore Piping indicates that no age-related cracking has been identified, thus PBN remains a Category A plant per NUREG-2191, Table XI.M35-1. A review of the 17 inspections for Unit 1 and 11 inspections for Unit 2 selected for initial license renewal performed between 2013 and 2018 did not reveal any relevant indications noted on the exam datasheets.

Additionally, a review of LERs identical to that for industry OE was performed using keyword searches (crack and Class 1) for PBN. The review identified no results.

Several post-approval NRC reviews have been performed since 2010. The NRC reviews the licensing basis, program basis document, implementing procedures, NDE records, and related CRs; and interviewed the plant personnel responsible for the AMPs. The NRC verified that program implementing documents contain the appropriate License Renewal references. The inspectors verified that the program and enhancements were in place to ensure that inspections for the applicable aging effects are performed and any noted indications are appropriately evaluated.

In 2018, an effectiveness review of the ISI AMP was performed following the guidelines provided in NEI 14-12, Aging Management Program Effectiveness. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (Element 4), corrective action (Element 7), and operating experience (Element 10). The effectiveness review found that ISI AMP continues to be effectively implemented. Full AMP effectiveness reviews are performed at least every five years.

To date, no enhancements to the AMP have been identified as a result of OE. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN ASME Code Class 1 Small-Bore Piping AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN ASME Code Class 1 Small-Bore Piping AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended functions of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.23 External Surfaces Monitoring of Mechanical Components

Program Description

The PBN External Surfaces Monitoring of Mechanical Components AMP is an existing AMP that was formerly the PBN Systems Monitoring Program. The PBN External Surfaces Monitoring of Mechanical Components AMP is a condition monitoring program that manages loss of material, cracking, hardening or loss of strength (of elastomeric components), loss of preload for HVAC closure bolting, reduction of heat transfer due to fouling (air to fluid heat exchangers), and reduction of thermal insulation resistance due to moisture intrusion. This AMP also inspects the integrity of coated surfaces as an effective method for managing the effects of corrosion on the metallic surfaces.

Visual inspections are performed during system inspections and walkdowns. The inspection parameters for metallic components include material condition, which consists of evidence of rust, general, pitting, and crevice corrosion; surface imperfections such as cracking and wastage, coating degradation such as cracking, flaking, or blistering; evidence of insulation damage or wetting, leakage, and accumulation of debris on heat exchanger surfaces. Coating degradation is used as an indicator of possible degradation on underlying surfaces of the component. Inspection parameters for elastomeric and polymeric components include hardening, discoloration, surface cracking, crazing, scuffing, loss of thickness, exposure of internal reinforcement, and dimensional changes. For certain materials, such as flexible polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual inspections conducted under this program.

ASME Code inspections are conducted in accordance with the applicable code requirements. Non-ASME Code inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance offset, surface coverage, and presence of protective coatings.

Non-stainless steel components are inspected to detect age-related degradation at a frequency not to exceed one refueling cycle. This frequency accommodates inspections of components that may be in locations normally accessible only during refueling outages (e.g., high dose areas). Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

Periodic visual inspections or surface examinations are conducted on stainless steel and aluminum components to manage cracking every 10 years during SPEO. Surface examinations or VT-1 examinations are conducted on 20 percent of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections. Aging effects associated with below grade components that are accessible during normal operations or refueling outages, for which access is not restricted, are managed by the PBN External Surfaces Monitoring of Mechanical Components AMP.

These visual inspections also inspect for external corrosion under insulation. A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point) are also periodically inspected at a minimum of every 10 years during the SPEO. Sample inspections are conducted of each material type and environment where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, significant moisture can accumulate under insulation during high humidity seasons, even in conditioned air. A minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Alternatively, any combination of a minimum of 25 1-foot axial length sections and components for each material type is inspected. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the component), and lowest design margin.

Alternative methods for detecting moisture/corrosion inside piping insulation (such as thermography, neutron backscatter devices, and moisture meters) will be used for inspecting piping jacketing that is not installed in accordance with plant-specific procedures (such as no minimum overlap, wrong location of seams, etc.).

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the SPEO. Qualitative acceptance criteria are clear enough to reasonably ensure a singular decision is derived based on observed conditions. The PBN External Surfaces Monitoring of Mechanical Components AMP also visually inspects the external surfaces of heat exchanger surfaces exposed to air (e.g., ventilation heat exchanger fins) for evidence of reduction of heat transfer due to fouling.

For situations where the internal (inaccessible) and external (accessible) surface environments are similar, such that the external (accessible) surface condition is representative of the internal (inaccessible) surface condition, then visual inspection of the accessible surfaces/components is performed. The PBN External Surfaces Monitoring of Mechanical Components AMP procedures provide the basis to establish that the external and internal surface condition and environment are sufficiently similar. These inspections provide reasonable assurance that the following effects are managed:

a. Loss of material/cracking of internal surfaces for metallic components.
b. Loss of material/cracking of internal surfaces for polymeric components.
c. Hardening or loss of strength of internal surfaces for elastomeric components.

Depending on the material, components may be coated to mitigate corrosion by protecting the external surface of the component from environmental exposure. Inspections to verify the integrity of the insulation jacketing are performed per the PBN External Surfaces Monitoring of Mechanical Components AMP procedures.

The PBN External Surfaces Monitoring of Mechanical Components AMP procedures define acceptance criteria that are utilized during inspection walkdowns to identify deficiencies in the in-scope component groups. PBN External Surfaces Monitoring of Mechanical Components AMP procedures require corrective actions be initiated for deficiencies identified during the walkdowns to ensure that loss of component intended functions does not occur. The PBN External Surfaces Monitoring of Mechanical Components AMP procedures utilize guidance from the EPRI Technical Report TR-1007933 (Reference 1.6.67), "Aging Assessment Field Guide," for identifying metal degradation and corrosion mechanisms. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection and the degradation is a valid indication or trend, then a CR is issued to perform an assessment and document the appropriate actions and recommendations; which may include the adjustment of inspection frequencies. When a CR is generated, the associated corrective action is documented in accordance with the PBN CAP and the CRs require the determination of probable cause and actions to prevent recurrence for significant conditions adverse to quality.

NUREG-2191 Consistency

The PBN External Surfaces Monitoring of Mechanical Components AMP, with enhancements, will be consistent with the ten elements of NUREG-2191, Section XI.M36, "External Surfaces Monitoring of Mechanical Components."

Exceptions to NUREG-2191

None

Enhancements

The PBN External Surfaces Monitoring of Mechanical Components AMP will be enhanced as follows for alignment with NUREG-2191. Enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement

1. Scope of Program	• Revise procedure(s) to inspect heat exchanger surfaces exposed to air for evidence of reduction of heat transfer due to fouling.
	• Specify in procedure(s) that situations where the similarity of the internal and external environments are such that the external surface condition is representative of the internal surface condition, external inspections of components may be credited for managing:
	  ○ loss of material and cracking of internal surfaces for metallic and cementitious components,
	  ○ loss of material, and cracking of internal surfaces for polymeric components, and
	  ○ hardening or loss of strength of internal surfaces for elastomeric components. When credited, the program provides the basis to establish that the external and internal surface condition and environment are sufficiently similar.
	• Clarify in procedure(s) that aging effects associated with below grade components that are accessible during normal operations or refueling outages, for which access is not restricted are managed by the PBN External Surfaces Monitoring of Mechanical Components AMP.

Element Affected	Enhancement
2. Preventative Action	• Revise procedure(s) to include an item in the walkdown checklist to inspect insulation metallic jacketing for any damage that would permit in-leakage of moisture.
3. Parameters Monitored or Inspected	• Revise procedure(s) to clarify visual inspection of cementitious components for indications [of] loss of material and cracking. Examples of inspection parameters for cementitious materials include spalling, scaling, and cracking. • Revise procedure(s) to clarify periodic visual or surface examinations are utilized to manage cracking in stainless steel or aluminum components. • Revise procedure(s) to add the following inspection parameters for metallic components: ○ Surface imperfections, loss of wall thickness, oxide coated surfaces ○ Corrosion stains on thermal insulation ○ Blistering of protective coating ○ Evidence of leakage (for detection of cracks) on the surfaces of stainless steel and aluminum components ○ Accumulation of debris on heat exchanger tube surfaces and air-side heat exchanger surfaces • Revise procedure(s) to include inspection for elastomeric and polymeric components and its methodology. Elastomeric and flexible polymeric components are monitored through a combination of visual inspection and manual or physical manipulation of the material. Visual inspections cover 100 percent of accessible component surfaces. Manual or physical manipulation of the material includes touching, pressing on, flexing, bending, or otherwise manually interacting with the material in order to reveal changes in material properties, such as hardness, and to make the visual examination process more effective in identifying aging effects such as cracking. The sample size for manipulation is at least 10 percent of available surface area. The inspection parameters for elastomers polymers shall include the following: ○ Surface cracking, crazing, scuffing, and dimensional change (e.g., “ballooning” and “necking”) ○ Loss of thickness ○ Discoloration (evidence of a potential change in material properties that could be indicative of polymeric degradation) ○ Exposure of internal reinforcement for reinforced elastomers ○ Hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate to manipulation • Revise procedure(s) to include that flexing of polyvinyl chloride piping exposed directly to sunlight (i.e., not located in a structure restricting access to sunlight such as manholes, enclosures, and vaults or isolated from the environment by coatings) is conducted to detect potential reduction in impact strength as indicated by a crackling sound or surface cracks when flexed. • Revise procedure(s) to include accumulation of debris on in-scope components is monitored.

Element Affected	Enhancement
4. Detection of Aging Effects	• Revise procedure(s) to inspect a sample of HVAC closure bolting in reach to ensure that it is not loose. • Revise procedure(s) to specify that inspections are to be performed by personnel qualified in accordance with site procedures and programs to perform the specified task, and when required by the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), inspections are conducted in accordance with the applicable code requirements. • Revise procedure(s) to include inspections for loss of material, cracking, changes in material properties, hardening or loss of strength (of elastomeric components), reduced thermal insulation resistance, loss of preload for HVAC closure bolting, and reduction of heat transfer due to fouling at an inspection frequency of every refueling outage for all in-scope non-stainless steel and non-aluminum components, which include metallic, polymeric, insulation jacketing (insulation when not jacketed). Non-ASME Code inspections and tests should include inspection parameters for items such as lighting, distance offset, surface coverage, and presence of protective coatings. Surfaces that are not readily visible during plant operations and refueling outages should be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained. • Revise procedure(s) to specify that surface examinations, or ASME Code Section XI VT-1 examinations (including those inspections conducted on non-ASME Code components) are conducted every 10 years to detect cracking of stainless steel (SS) and aluminum components. • Revise procedure(s) to specify that surface examinations, or ASME Code Section XI VT-1 examinations, are conducted on 20 percent of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections. The provisions of GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to conduct inspections in a more severe environment and combination of air environments may be incorporated for these inspections. • Revise procedure(s) to specify alternative methods for detecting moisture inside piping insulation (such as thermography, neutron backscatter devices, and moisture meters) are to be used for inspecting piping jacketing that is not installed in accordance with plant-specific procedures (such as no minimum overlap, wrong location of seams, etc.). Revise procedure(s) to include the following information: o Component surfaces that are insulated and exposed to condensation (because the in-scope component is operated below the dew point), and insulated outdoor components, are periodically inspected every 5 years during the SPEO. o For all outdoor components and any indoor components exposed to condensation (because the in-scope component is operated below the dew point), inspections are conducted of each material type (e.g., steel, SS, copper alloy, aluminum) and environment (e.g., air outdoor, air accompanied by leakage) where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, significant moisture can accumulate under insulation during high humidity seasons, even in conditioned air. A minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area

Element Affected	Enhancement
	for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Alternatively, any combination of a minimum of 25 1-foot axial length sections and components for each material type is inspected. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the component), and lowest design margin. Inspections for cracking due to SCC in aluminum components need not be conducted if it has been determined that SCC is not an applicable aging effect. • Revise procedure(s) to specify that: o Visual inspection will identify direct indicators of loss of material due to wear to include dimension change, scuffing, and, for flexible polymeric materials with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. o Visual inspection of elastomers and flexible polymers will identify indirect indicators of elastomer and flexible polymer hardening or loss of strength, including the presence of surface cracking, crazing, discoloration, and, for elastomers with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. o Visual inspections will cover 100 percent of accessible component surfaces. • Manual or physical manipulation can be used to augment visual inspection to confirm the absence of hardening or loss of strength for elastomers and flexible polymeric materials (e.g., heating, ventilation, and air conditioning flexible connectors) where appropriate, and the sample size for manipulation is at least 10 percent of available surface area.
5. Monitoring and Trending	• Revise procedure(s) to formalize sampling-based inspections. The results of sampling-based inspections will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain intended functions of the components throughout the subsequent period of extended operation based on the projected rate and extent of degradation. • The AMP owner will interface with the fleet corrosion monitoring action program to identify problem areas and track resolution of deficiencies.
6. Acceptance Criteria	• Revise procedure(s) to add an evaluation to project the degree of observed degradation to the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. • Revise procedure(s) to specify where practical, acceptance criteria are quantitative (e.g., minimum wall thickness, percent shrinkage allowed in an elastomeric seal). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. Where qualitative acceptance criteria are used, the criteria are clear enough to reasonably ensure that a singular decision is derived based on the observed condition of the systems, structures, and components (e.g. cracks are absent in rigid polymers, the flexibility of an elastomeric sealant is sufficient to ensure that it will properly adhere to surface). • Include guidance from EPRI TR-1007933 “Aging Assessment Field Guide”, and TR-1009743 “Aging Identification and Assessment Checklist”, on the evaluation of materials and criteria for their acceptance when performing visual/tactile inspections.
7. Corrective Actions	• Revise procedure(s) to specify that additional inspections will be performed if any sampling-based inspections to detect cracking in

Element Affected	Enhancement
	aluminum and stainless steel components do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination inspected, whichever is less. The additional inspections will be completed within the interval (e.g., 10-year inspection interval) in which the original inspection was conducted. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent-of-cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2.

Operating Experience

Industry Operating Experience

- NRC IN 2011-04 provides insight regarding the potential for outside diameter stress corrosion cracking (ODSCC). The PBN External Surfaces Monitoring of Mechanical Components AMP was revised to address the potential for ODSCC in stainless steel piping systems.

- INPO IER L3-13-25 provided insight regarding a manual reactor scram due to degrading condenser vacuum. The report recommended a) a thorough analysis to understand the risk of the off-normal alignment and to identify mitigating actions that may be needed, b) review and revise, as necessary, management systems including work management, corrective action, system health, and observation programs to ensure that the importance or impacts of subtle problems are addressed. The PBN External Surfaces Monitoring of Mechanical Components AMP was revised to address the observations from this IER.

- In 2017, NRC inspection reports (05000250/2017003, 05000250/2017007, 05000250/2017004) identified ineffectiveness and an adverse trend related to the External Surfaces Monitoring of Mechanical Components AMP at Turkey Point. In response, a fleet corrosion monitoring action program procedure was developed. The purpose of this procedure is to clarify the requirements and strategies to monitor and control externally initiated general and localized corrosion of important equipment and piping in outdoor or exposed environments. The PBN External Surfaces Monitoring of Mechanical Components AMP was enhanced to include interfacing with the fleet corrosion monitoring action program to identify problem areas and track resolution of deficiencies.

Plant Specific Operating Experience

A review of plant operating experience indicates that numerous work orders, condition reports/action requests have been issued as a result of the discovering aging mechanisms for the PBN External Surfaces Monitoring of Mechanical Components AMP.

- In 2010 and 2013, the NRC performed the 71003 Phase 2 inspection at PBN Unit 1 and Unit 2, respectively. Commitments required that the PBN External Surfaces Monitoring of Mechanical Components AMP be enhanced prior to the period of extended operation, and that all systems within the scope of license renewal containing components requiring an aging management review and that credit the AMP for managing the effects of aging on the external surfaces of the components be walked down at a minimum frequency of once per operating cycle, within the limits of accessibility. Specific enhancements for supervisory review and evaluation were also included as part of the commitments. The inspectors reviewed the licensing basis, the AMP basis documentation, implementing procedures, planned and completed work orders, related corrective action documents, and interviewed the plant personnel responsible for this program. The inspectors verified that PBN conducted periodic inspections of the fire protection system and the service water system, and that PBN had enhanced the program as specified in the SER. The inspectors verified that supervisors of each system performed reviews and documented the results to ensure that the accessible portions of each system were walked down at a minimum frequency of once per operating cycle. The inspectors verified that the PBN evaluated inaccessible areas of various systems to ensure that accessible areas walked down contained the same material(s) and the same or more severe environment(s) as those portions that were considered inaccessible. The inspectors also verified that the system engineers had the appropriate qualifications to perform walk-downs, and that operating experience was used appropriately per procedure. The inspectors verified that the commitments related to the PBN External Surfaces Monitoring of Mechanical Components AMP were met.

- In 2018, an effectiveness review of the PBN External Surfaces Monitoring of Mechanical Components AMP was performed following the guidelines provided in NEI 14-12, Aging Management Program Effectiveness. The effectiveness review covered the applicable ten program elements with focus on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). The effectiveness review found the PBN External Surfaces Monitoring of Mechanical Components AMP to be effectively implemented with no gaps. A weakness was found in pump house walkdowns where two examples of degraded piping were noted. Specifically, the fire pump diesel fuel oil supply line had wall loss due to corrosion and fire protection piping was found corroded but not corrected in a timely manner. Repairs were made to the piping and the PBN External Surfaces Monitoring of Mechanical Components AMP procedure was updated to emphasize the importance of inspecting areas that are frequently wetted such as the pump house.

- In 2018, a valve operator broke which allowed the valve to travel to mid position causing various circulating water (CW) system alarms and ultimately a manual trip of the Unit 1 reactor. The interior lip of the base plate to the torque tube collected moisture and sodium hypochlorite from prior leaks allowed accelerated corrosion due to constant exposure to the chemical/water. The valve operator was replaced. Although this component was not in-scope of the PBN External Surfaces Monitoring of Mechanical Components AMP, similar circumstances could be found in SSCs that are in scope for the aging management program. The PBN External Surfaces Monitoring of Mechanical Components AMP procedure was updated to address the findings from this issue.

- In 2019, the NRC performed the 71003 Phase 4 inspections at PBN Units 1 and 2. The team selected seven AMPs for evaluation considering risk insights and programs that were enhanced or new under the renewed operating license. The PBN External Surfaces Monitoring of Mechanical Components AMP was not one of the AMPs selected for this inspection.

- Additional Items

  - In March 2016, small rusted areas on uninsulated Service Water return piping from the containment fan cooler coils inside containment were identified. Numerous small rusted areas (typically less than 1 square inch) were identified during the walkdown. Operability of containment sump "B" due to debris was not challenged as there were no substantial pieces of loose flaking paint. Work requests were initiated to clean and repaint the areas during the next refueling outage.

  - In November 2016, an informal inspection found paint peeling and rust on diesel fuel oil above ground fuel oil storage tanks and associated piping. An AR was issued requesting an evaluation of the condition of the coating on the tanks and piping and determine if maintenance (i.e. recoating) was required.

  - In April 2017, loss of material due to general corrosion of the external surface of lube oil piping was identified in an environment of indoor air. During a Gas Turbine walkdown, minor surface rust was identified on an elbow of a lube oil supply line on the east side of the building. There was no concern regarding the operation of gas turbine due to this corrosion, but the importance of proactive measures to stop the spread of corrosion in the area was recognized. The AR requested that the elbow be cleaned and repainted along with minor rust spots on other lube oil piping in the area.

  - In March 2018, loss of material due to general corrosion was identified on the external surfaces of fire protection supply header piping which had become submerged where the piping exits the CW pumphouse.

Work Orders (WO) were issued to clean and coat the sections of piping and to address why the piping had become submerged.

- In May 2018, an action request (AR) was issued noting that there may be a gap in how PBN monitors changes in degraded conditions of SSCs. Corrosion of submerged fire protection piping was presented as one of the examples. The AR identified that long term degradation of SSCs is a plant responsibility which includes identification, prioritizing and scheduling the work, and that each work group has a part. The AR indicated that a collaborative effort was needed to improve targeting and long-term monitoring of important SSCs that are degraded but have been determined to be functional and operable to ensure conditions do not degrade to the point where operability or functionality are impacted without resolution or awareness. In accordance with discussion with the maintenance rule committee (MRC), select conditions/issues that might be subject to change/degradation are periodically revisited to ensure that they do not fall into a FDB or OBD category with timeframes as agreed by MRC.

- In June 2019, surface corrosion on the bodies of auxiliary feedwater valves was identified during a system walkdown with Engineering management. Work requests were initiated to clean and coat the valve bodies and associated exposed carbon steel piping.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN External Surfaces Monitoring of Mechanical Components AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN External Surfaces Monitoring of Mechanical Components AMP, with enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.24 Flux Thimble Tube Inspection

Program Description

The PBN Flux Thimble Tube Inspection AMP, previously known as the PBN Thimble Tube Inspection Program, is an existing condition monitoring program used to inspect for thinning of the flux thimble tube wall, which provides a path for the incore neutron flux monitoring system detectors and forms part of the RCS pressure boundary. This AMP manages the aging effect of loss of material due to fretting wear.

The flux thimble tube inspection associated with this AMP encompasses all of the flux thimble tubes that form part of the RCS pressure boundary. This AMP monitors flux thimble tube wall thickness to detect loss of material from the flux thimble tubes during the SPEO. The 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. Periodic eddy current testing (ECT) is used to monitor for loss of material and wear of the flux thimble tubes during the SPEO. This inspection AMP implements the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors."

The frequency of examinations is based on site-specific wear data and wear predictions. The basic examination schedule was developed by Westinghouse based on evaluation of results obtained from the 2004 and 2005 refueling outages. Flux thimble tube wear rates are projected over future operating cycles and future examination intervals are determined based on the disposition of examination results and engineering evaluations that have been completed, as this is required to substantiate the decision for an alternate examination interval.

Flux thimble tube wall thickness measurements are trended, and wear rates are calculated using the methodology of WCAP-12866, "Bottom Mounted Instrumentation Flux Thimble Wear" (Reference 1.6.68). The methodology set forth in this document includes sufficient conservatism to ensure that wall thickness acceptance criteria continue to be met during plant operation between scheduled inspections. Corrective actions are taken when trending results project that acceptance criteria would not be met prior to the next planned inspection or the end of the SPEO.

Inspection results (including wall loss) are reported using the PBN CAP and are provided to the appropriate engineering personnel who evaluate, disposition and recommend any necessary corrective actions. The evaluation must determine the need for repositioning, capping or replacing the applicable worn flux thimble tubing, or may provide justification to retain the original configuration of the existing flux thimble tube if it remains within the acceptance criteria. A maximum depth of 80 percent through-wall wear with a maximum scar length of 5.0 inches was established as the maximum acceptable through-wall wear, based on WCAP-12866. A more conservative depth of 60 percent through-wall wear is applied at PBN to ensure that the integrity of the RCS pressure boundary is maintained. This conservative depth includes allowances for instrument uncertainty and other inaccuracies.

NUREG-2191 Consistency

The PBN Flux Thimble Tube Inspection AMP, with enhancement, will be consistent with the 10 elements of NUREG-2191, Section XI.M37, “Flux Thimble Tube Inspection.”

Exceptions to NUREG-2191

None.

Enhancements

The PBN Flux Thimble Tube Inspection AMP will be enhanced as follows for alignment with NUREG-2191. There are no new inspections required for SLR; however, existing inspection frequencies may change based on inspection results. The enhancement is to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
7. Corrective Actions	Revise the governing AMP procedure to state the following: Flux thimble tubes that cannot be inspected over the tube length, that are subject to wear due to restriction or other defects, and that cannot be shown by analysis to be satisfactory for continued service, are removed from service to maintain the integrity of the RCS pressure boundary.

Operating Experience

Industry Operating Experience

Bottom-mounted instrumentation flux thimble tubing thinning caused by flow induced vibration was first reported in 1981 in three thimble tubes at the Salem plant. Subsequent inspections at the Salem plant and other plants identified additional worn flux thimble tubing, some with significant wall loss. In 1987, the NRC issued Information Notice 87-44, "Thimble Tube Thinning in Westinghouse Reactors." In July of 1988, the NRC issued Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors." This bulletin requested operators to establish a monitoring program to monitor thimble tube performance.

In response, PBN established the PBN Flux Thimble Tube Inspection AMP and performed eddy current testing (ECT) of the flux thimble tubes in both units. As a result of the testing, five tubes on Unit 1 were replaced due to wear even though three of the tubes were not at minimum wall thickness nor did calculations indicate that they would reach minimum wall thickness prior to the next inspection. They were replaced as a conservative measure.

Plant Specific Operating Experience

Review of inspection results 2000 through the most recent inspections have indicated that loss of material due to wear of the flux thimble tubes has generally been a decelerating phenomenon as the wear starts rapidly and then plateaus.

Review of the most recent inspection results (Fall 2017 for Unit 1 and Spring 2017 for Unit 2) indicates that the worst-case flux thimble tube wall loss for Unit 1 was less than 45 percent and for Unit 2 was less than 40 percent.

The PBN Flux Thimble Tube Inspection AMP is a mature, established program. Its effectiveness has been demonstrated as a result of the October 2010 and March 2013 NRC Phase 2 post-approval site inspections (Inspection Reports 05000266/2010-011 and 05000301/2013008) which were conducted prior to entering into the PEO for each unit. The inspectors reviewed the licensing basis, program basis document, implementing procedures, and completed inspections; and interviewed the PBN plant personnel responsible for this program. The inspectors verified that program and associated enhancements were in place. Based on review of the timeliness and adequacy of PBN's actions, the inspectors determined PBN had met the required commitments for the PBN Flux Thimble Tube Inspection AMP.

An effectiveness review of the PBN Flux Thimble Tube Inspection AMP was performed in 2018 following the guidelines provided in NEI 14-12, Aging Management Program Effectiveness. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (Element 4), corrective action (Element 7), and operating experience (Element 10). The review found that the PBN Flux Thimble Tube Inspection AMP was effective.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Flux Thimble Tube Inspection AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Flux Thimble Tube Inspection AMP, with an enhancement, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of this AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new condition monitoring AMP that manages the aging effects of loss of material, cracking, reduction of heat transfer due to fouling, flow blockage, and hardening or loss of strength of elastomeric and polymeric materials. Some inspections and activities within the scope of the new AMP were previously performed by the PBN Periodic Surveillance and Preventive Maintenance Program.

The PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP consists of inspections of the internal surfaces of piping, piping components, ducting, heat exchanger components, and other components exposed to potentially aggressive environments. These environments include air, air with borated water leakage, condensation, gas, diesel exhaust, fuel oil, lubricating oil, and any water-filled systems. Aging effects associated with components (except for elastomers and flexible polymeric components) within the scope of the PBN Open-Cycle Cooling Water System AMP (Section B.2.3.11), the PBN Closed Treated Water Systems AMP (Section B.2.3.12), and the PBN Fire Water System AMP (Section B.2.3.16) will not be managed by this AMP. Aging effects associated with elastomers and flexible polymeric components installed in open-cycle cooling water, closed-cycle cooling water, ultimate heat sink, and fire water systems will be managed by this AMP in lieu of the AMPs listed above.

Internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. The AMP includes visual inspections and when appropriate, surface examinations. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this AMP. At a minimum, in each 10-year period during the SPEO, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 19 components per unit is inspected. The maximum of 19 components per unit for inspection is used in lieu of 25 components per unit due to PBN being a two-unit plant with sufficiently similar operating conditions at each unit (e.g., flowrate, chemistry, temperature, excursions), similar time in operation for each unit, similar water sources, and similar operating frequency.

Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections will continue in each period despite meeting the sampling limit.

Internal visual inspections used to assess loss of material will be capable of detecting surface irregularities that could be indicative of an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected for steel components exposed to raw water, raw water (potable), or waste water, follow-up volumetric examinations will be performed.

Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions. Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the SPEO. Qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions. Corrective actions are performed as required based on the inspections results.

This AMP is also used to manage cracking due to stress corrosion cracking (SCC) in aluminum and stainless steel (SS) components exposed to aqueous solutions and air environments containing halides. This AMP is not used to manage components where visual inspection of internal surfaces is not possible unless specific volumetric inspections are performed as noted above.

This AMP does not manage components in which recurring internal corrosion is a known issue. If operating experience indicates that there has been recurring internal corrosion, a plant-specific AMP will be necessary unless this AMP, or another new or existing AMP, includes augmented requirements that address recurring aging effects (e.g., Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR) Sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6). Following failure due to recurring internal corrosion, this AMP may be used if the failed material is replaced by one that is more corrosion resistant in the environment of interest, or corrective actions have been taken to prevent recurrence of the recurring internal corrosion.

The PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will have a new governing and inspection procedure consistent with NUREG-2191, Section XI.M38.

The PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP implementation will be completed no later than 6 months prior to the SPEO or no later than the last refueling outage prior to the SPEO.

NUREG-2191 Consistency

The PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be consistent with the ten elements of NUREG-2191, Section XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

- The following OE from NUREG-2191 Section XI.M38 is relevant to PBN:

  Inspections of internal surfaces during the performance of periodic surveillance and maintenance activities have been in effect at many utilities in support of plant component reliability programs. These activities have proven effective in maintaining the material condition of plant systems, structures, and components. The elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and staff expectations. The applicant evaluates recent OE and provides objective evidence to support the conclusion that the effects of aging are adequately managed.

  The review of plant-specific OE during the development of this program is to be broad and detailed enough to detect instances of aging effects that have occurred repeatedly. In some instances, repeatedly occurring aging effects (i.e., recurring internal corrosion) might result in augmented aging management activities. Further evaluation aging management review line items in SRP-SLR Sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6, “Loss of Material due to Recurring Internal Corrosion,” include criteria to determine whether recurring internal corrosion is occurring, and recommendations related to augmenting aging management activities.

  The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE including research and development such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

- Recent industry OE was reviewed from the SLR Safety Evaluation Reports for the first three submitted SLRAs (Turkey Point, Peach Bottom, and Surry).

  - The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP must include statements that (a) surface examinations or ASME Code Section XI VT-1 examinations are conducted to detect cracking of stainless steel and aluminum components; and (b) opportunistic inspections continue in each period despite meeting the sampling limit.

    PBN has incorporated these requirements into the PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP

<u>Plant Specific Operating Experience</u>

- Inspections Performed
    - March 2010 Residual Heat Removal (RHR) Heat Exchanger Inspections

      Degradation due to tube-to-support plate and tube-to-tube contact was found during inspection of the Unit 1 'A' RHR heat exchanger, which was completed under the initial license renewal One Time Inspection AMP. The degradation required 10 tubes to be plugged. The scope of inspection was then expanded to inspect the Unit 1 'B' RHR heat exchanger, which found similar tubing degradation, although the extent of the degradation was significantly less and no tubes required plugging. Based on these results, the scope was again expanded to include both Unit 2 RHR heat exchangers. Both Unit 2 RHR heat exchangers were inspected during a subsequent refueling outage and found to have much less degradation. However, because the design of the four heat exchangers is the same and based on the inspection results, preventive maintenance activities were generated to inspect the RHR heat exchangers using eddy current testing periodically to monitor for degradation due to this aging effect. These activities are currently in the initial license renewal PSPM Program but will be moved to the new PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP for SLR.

    - April 2010 Sewage Treatment Plant Piping Inspections

      The piping of interest is in the central area of the Primary Auxiliary Building (PAB) and was inspected under the initial license renewal One-Time Inspection AMP. Degradation was identified in the carbon steel lines. This system piping does not have chemistry control; therefore, periodic inspection of this piping was added to the scope of the PSPM Program. A preventive maintenance activity was created which requires periodic wall thickness inspections of this piping at multiple locations within the PAB. The next inspection was completed in April 2012, which found UT readings similar to the previous inspection. This confirmed that the corrosion rate is slow and there is reasonable assurance that the intended function of the piping will be maintained. This activity will be moved to the new PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP for SLR.

    - March 2011 RHR Flow Control Valve Inspections

      A Unit 2 RHR system flow control valve was originally inspected under the initial license renewal One-Time Inspection AMP and identified cavitation damage on the downstream flange area, with the damaged area still well above minimum required wall thickness. The valve was re-inspected in 2014 and 2015, and no discernable change in the condition of the degradation was found. These trended inspection results demonstrate the degradation is progressing slowly and will not impact the component intended function. An inspection was also performed on the corresponding Unit 1 valve, which found some cavitation damage, but to a lesser extent than the Unit 2 valve. An inspection on the opposite train Unit 1 valve will be completed within the next two refueling outages. The results of that inspection will determine whether additional or periodic inspections are required to provide reasonable assurance that the component intended function will continue to be maintained. This inspection requirement has been documented as a regulatory commitment in the SLRA Appendix A.

- September 2012 G-01 Exhaust Piping Ultrasonic Testing

  UT was performed on diesel generator exhaust piping and found locations that did not meet the acceptance criteria. The readings did not challenge the minimum wall thickness of the piping. This piping is periodically inspected under the PSPM Program for initial license renewal and will be managed going forward under the new PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP for SLR. Corrective actions were completed by building up the wall thickness of the piping to the as-built condition with weld material.

- September 2015 Unit 2 Screen Wash Piping Ultrasonic Testing

  UT was performed on 8-inch diameter screen wash piping and found locations that did not meet the acceptance criteria. The readings did not challenge the minimum wall thickness of the piping. This piping is periodically inspected under the PSPM Program for initial license renewal and will be managed going forward under the new PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP for SLR. Periodic inspections will trend the wall thickness results and no further actions are required.

- Additional Items

  - March 2010: A visual exam of the Unit 1 reactor coolant pump oil collection tank recorded minor surface corrosion on the carbon steel internal surface. The surface corrosion did not appear to be of significant depth and would not impact the intended function of the oil collection system.

  - November 2011: Non-destructive examinations (NDEs) noted significant degradation due to MIC on the service water side of a cable spreading room air conditioning unit. Adjacent piping was also examined which found heavy deposits/tubercules. Multiple locations on the outlet tube sheet were noted to be below minimum wall thickness for tube sealing, and an area in the center of the outlet tube sheet showed wall loss to below the design minimum wall thickness. Corrective actions were initiated which resulted in replacing the air conditioning units.

  - March 2013: During service water piping maintenance activities, the material condition of some 1-inch service water piping was found unsatisfactory, displaying rust and internal corrosion that caused the pipe to fail when the couplings were removed. The 1-inch piping was evaluated and subsequently replaced.

- April 2013: Two service water relief valves failed a bench test which is indicative of slight bonding at the disc/seat interface. The valves had minor internal corrosion but no external or internal valve damage. The valves were subsequently replaced.

- March 2014: Wall thinning due to internal corrosion was identified during radiographic inspection in 8-inch service water piping. The wall thinning did not challenge the minimum wall thickness and the piping was determined to be fully operable. Trending and further monitoring of this pipe wall thickness is continuing under the service water inservice inspection program.

- June 2015: Two Emergency Diesel Generator starting air compressor discharge expansion joints had internal corrosion. They were determined to be acceptable for use but required replacement during the next diesel outage. The expansion joints were subsequently replaced during the following diesel outage.

- March 2016: Pitting was found in a boric acid blender flow control valve along with evidence of slight cavitation around the pitting. The valve body material was ASTM-A351 Gr. CF8 (cast austenitic SS). The rust-colored pitting was evaluated as minor in nature with no concern for the degradation challenging the integrity of the pressure boundary. No repair was required for this pitting.

- December 2017: A service water vent plug (carbon steel in raw water) was leaking and found to have experienced approximately 50 percent material loss. Both the associated valve and plug were replaced. An aging management review performed resulted in recommending additional replacements to proactively manage this issue. As a result, two similar fittings were replaced on the service water supply piping.

- October 2018: Eddy current testing (ECT) of the Unit 2 containment fan cooler tubes discovered that 7 U-tubes needed to be plugged. The tube degradation was from internal corrosion. ECT readings were validated and reports reviewed by fleet engineers for concurrence. Recommendations were made to plug tubes approaching 35 percent wear and adjust the inspection preventive maintenance activities to account for this change in condition. The tubes were subsequently plugged in accordance with the above recommendations and preventive maintenance activities revised to include inspection of these plugs.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.26 Lubricating Oil Analysis

Program Description

The PBN Lubricating Oil Analysis AMP is an existing AMP that includes activities previously performed as part of plant predictive maintenance. The PBN Lubricating Oil Analysis AMP manages loss of material due to corrosion and loss of heat transfer in components exposed to lubricating oil within the scope of SLR by maintaining the required fluid quality to prevent or mitigate age-related degradation. The PBN Lubricating Oil Analysis AMP maintains lubricating oil and hydraulic oil system contaminants (water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. Testing activities include sampling and analysis of lubricating oil for contaminants which could be indicative of in-leakage and corrosion product buildup.

Although the PBN Lubricating Oil Analysis AMP is a sampling-based AMP, the AMP will be augmented to manage the effects of aging for SLR. Verification of the effectiveness of the PBN Lubricating Oil Analysis AMP will be conducted by the PBN One-Time Inspection AMP (Section B.2.3.20) on selected components at susceptible locations in lubricating and hydraulic oil environments. Inspections of components in lubricating oil environments were previously completed under the initial license renewal One-Time Inspection Program.

The PBN Lubricating Oil Analysis AMP maintains oil system contaminants (such as water, debris, oxidation/viscosity, and fuel dilution) within acceptable limits and performs sampling for water, particle count, and other parameters to detect evidence of contamination by moisture or excessive corrosion. Water and particle concentration are not to exceed limits based on equipment manufacturer's recommendations or industry standards. In addition, phase-separated water (free water) in any amount is not acceptable. Equipment with oil sample results exceeding alert limits may be subjected to actions including, but not limited to resampling, increased sampling frequency, and additional monitoring and trending of select parameters.

NUREG-2191 Consistency

The PBN Lubricating Oil Analysis AMP, with enhancements, will be consistent with the ten elements of NUREG-2191, Section XI.M39, "Lubricating Oil Analysis".

Exceptions to NUREG-2191

None.

Enhancements

The PBN Lubricating Oil Analysis AMP will be enhanced as follows, for alignment with NUREG-2191, Section XI.M39. The PBN Lubricating Oil Analysis AMP implementation and enhancements will be completed no later than 6 months prior to the SPEO or no later than the last refueling outage prior to the SPEO.

Element Affected	Enhancement
1. Scope of Program	• Manage aging effects associated with in-scope piping and piping components exposed to an environment of hydraulic oil. • Manage aging effects associated with reactor coolant pump system components that are exposed to an environment of lubricating oil. In addition, manage other in-scope components exposed to lubricating oil environments and subject to aging management review.
2. Preventive Actions 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending	• Maintain contaminants in the in-scope lubricating oil and hydraulic oil systems within acceptable limits through periodic sampling and testing for moisture and particle count in accordance with industry standards. All lubricating oil analysis results will be reviewed and trended to determine if alert limits have been reached or exceeded, as well as, if there are any unusual or adverse trends associated with the oil sample.
4. Detection of Aging Effects	• Sampling and testing of old oil will be performed following periodic oil changes, or on a schedule consistent with equipment manufacturer's recommendations or industry standards [e.g., American Society of Testing Materials (ASTM) D 6224 02]. Plant specific operating experience associated with lubricating oil systems may also be used to adjust the schedule for periodic sampling and testing, when justified by prior sampling results. • For hydraulic fluids, if the fluid is replaced based on a periodicity recommended by the fluid manufacturer, equipment vendor, or plant-specific documents, testing is not required. Alternatively, the hydraulic fluid will be tested for water content if the oil is not clear or bright, and for particulate count.
6. Acceptance Criteria 7. Corrective Actions	• Compare the particulate count of the samples with acceptance criteria for particulates. The acceptance criteria for water and particle concentration within the oil must not exceed limits based on equipment manufacturer's recommendations or industry standards. If an acceptance criteria limit is reached or exceeded, actions to address the condition are to be taken. Corrective actions may include increased monitoring, corrective maintenance, further laboratory analysis, and engineering evaluation of the specified lubricating oil system. • Phase-separated water in any amount is not acceptable. If phase-separated water is identified in the sample, then corrective actions are to be initiated to identify the source and correct the issue (e.g., repair/replace component or modify operating conditions).

Operating Experience

Industry Operating Experience

The OE at some plants has identified (a) water in the lubricating oil and (b) particulate contamination. However, no instances of component failures attributed to lubricating oil contamination have been identified.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE including research and development such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

Plant Specific Operating Experience

Significant Inspections Performed

- 2009 through 2010, Inspections Under the One-Time Inspection Program
  - Unit 2 reactor coolant pump (RCP) motor upper oil cooler (shell and tubing)

    The carbon steel shells for the RCP motor oil coolers were inspected during RCP refurbishments, and no significant degradation was identified.

    The copper alloy (>15% Zn) tubing was eddy current tested and demonstrated that very little degradation was occurring.
  - Unit 1 RCP oil collection tank and drip pan

    A visual exam of the carbon steel Unit 1 RCP oil collection tank found minor surface corrosion on the internal surface. The surface corrosion was not of significant depth and would not impact the intended function of the oil collection system.

    A visual exam of the carbon steel Unit 1 RCP oil collection drip pan found no recordable indications.

    Unit 1 RCP oil collection drain tubing

    A visual exam of the copper alloy (>15% Zn) drain tubing was performed on a horizontal section of the tubing and on the connection to the drip pan. The exam found no recordable indications.
- July 2013: Oil analysis results for the Unit 1 auxiliary feedwater turbine driven pump indicated that the inboard turbine bearing oil contained 1323 ppm of water, which was noted immediately upon draining the oil and was not distributed in the oil. Water had settled on the bottom of the reservoir which was likely due to condensation from the cooling water bearings being in service for several weeks as part of a chlorination treatment. The as found

concentration of 1323 ppm was still well below the 5000 ppm limit and did not impact the ability of the pump to perform its intended function. The sampling activity included an oil change, so no further actions were required. A corrective action was also written to investigate alternatives to subjecting the bearing coolers to service water flow during long-run treatments.

- April 2014: An oil sample obtained from the Unit 2 auxiliary feedwater turbine driven pump had a dark grey/black appearance. Based on OE, this was an expected issue associated with break-in of new brass bearings. Besides color, all other parameters of the oil analysis were normal. The oil was changed and resampled after additional pump run time. The resampled oil was brighter, indicating that bearing wear-in was occurring as expected and oil quality was improving.

- October 2016: Emergency Diesel Generator lubricating oil analysis indicated a fuel oil concentration of 1.7 percent and 1.4 percent for the last two monthly samples. Normal is 0 percent-2.0 percent, borderline is 2.0 percent-5.0 percent, and the operability limit is at 5.0 percent. The history of trends for this EDG indicates that this is not a step change, as within the last year the minimum was 0.9 percent and maximum was 1.7 percent. This corrective action was written for trending purposes and does not question the ability of the component to perform its intended function.

- April 2017: Emergency Diesel Generator lubricating oil analysis indicated a trend of increasing fuel oil concentration. The fuel oil concentration was 0.2 percent. Normal is 0 percent-2.0 percent, borderline is 2.0 percent-5.0 percent, and the operability limit is at 5.0 percent. Previous samples indicated 0.0 percent, 0.1 percent, and 0.1 percent. A follow-up inspection was completed; however, the source of the suspected leak could not be determined. Because no leak was found, and the fuel oil concentration was within the normal band, no further actions were required. This corrective action was initiated in order to be proactive at identifying issues at a low level.

Program Owner Discussions - On February 6, 2020, an interview was held with the PBN Lubricating Oil Analysis AMP owner. The AMP owner noted that the AMP is based on existing activities which are part of a scrutinized, mature program. Currently, PBN samples for water content and corrosion products, among other parameters. ARs are written for any adverse findings, which could result in a preventive maintenance activity frequency change for sampling, etc.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Lubricating Oil Analysis AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Lubricating Oil Analysis AMP provides reasonable assurance that the effects of aging are being adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.27 Buried and Underground Piping and Tanks

Program Description

The PBN Buried and Underground Piping and Tanks AMP, previously known as the Buried Services Monitoring Program, is an existing condition monitoring program that manages the aging effects associated with the external surfaces of buried and underground piping and tanks such as loss of material and cracking. It addresses piping and tanks composed of metallic (carbon steel, low-alloy steel, and cast iron) materials that are within the scope of Subsequent License Renewal in the service water, fuel oil, and fire water.

It is noted that this AMP treats cast iron and cement lined cast iron as "steel." There are no polymeric, cementitious, or metallic materials other than those metals previously stated for the in-scope systems, therefore, the aging management of these materials is not applicable. The cementitious materials associated with the intake structure forebay and discharge piping are managed by the PBN Inspection of Water Control Structures Associated with Nuclear Power Plants AMP (Section B.2.3.35). Likewise, the interior surfaces of the coated, cement lined cast iron fire water system piping is managed by the PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section B.2.3.28).

This objective accomplished through the use of preventive, mitigative, inspection, and in some cases, performance monitoring activities. The PBN Buried and Underground Piping and Tanks AMP includes (a) preventive measures to mitigate degradation (e.g., external coatings/wrappings), (b) visual inspections of external surfaces of buried components for evidence of coating/wrapping damage, and (c) visual inspections of external surfaces of buried components for evidence of degradation, if the coating or wrapping is damaged or the pipe is uncoated or unwrapped, to manage the effects of aging. The periodicity of these inspections will be based on plant operating experience (OE) and opportunities for inspection such as scheduled maintenance work. These inspections will occur once prior to the SPEO and at least every 10 years during the SPEO. If an opportunity for inspection occurs prior to the scheduled inspection, the opportunistic inspection can be credited for satisfying the scheduled inspection.

The PBN Buried and Underground Piping and Tanks AMP manages applicable aging effects such as loss of material, cracking, and blistering. Depending on the material, preventive and mitigative techniques may include using external coatings, cathodic protection, and quality backfill. Depending on the material, inspection activities may include electrochemical verification of the effectiveness of cathodic protection, nondestructive evaluation of pipe or tank wall thicknesses, pressure testing of the pipe, performance monitoring of fire mains, and visual inspections of the pipe or tank from the exterior.

The primary materials used by the in-scope buried and underground pressure boundary retaining components are carbon steel, low-alloy steel, and cast iron. Additionally, some pipe segments associated with the fire protection ring header are composed of coated, cement lined cast iron piping. This AMP treats cast iron and cement lined cast iron as "steel." There are no polymeric, cementitious, or metallic materials other than those metals previously stated, therefore, the aging management of these materials is not applicable.

The primary tanks within the scope of this AMP are listed below:

- T-072, Emergency Fuel Oil Storage Tank (bitumastic coated carbon steel tank that is half buried)
- T-175A, G-01/G-02 EDG Fuel Oil Storage Tank (double walled, epoxy lined carbon steel tank located in an underground concrete vault associated with the diesel building)
- T-175B, G-03/G-04 EDG Fuel Oil Storage Tank (double walled, epoxy lined carbon steel tank located in an underground concrete vault associated with the diesel building)

NUREG-2191 Consistency

The PBN Buried and Underground Piping and Tanks AMP, with enhancements, will be consistent with exception with the 10 elements of NUREG-2191, Section XI.M41, “Buried and Underground Piping and Tanks.”

Exception to NUREG-2191

- The PBN cathodic protection was last evaluated in accordance with NACE SP0169-2013 rather than NACE SP0169-2007 specified in GALL-SLR. The PBN Buried and Underground Piping and Tanks AMP will take an exception to performing cathodic protection testing and evaluations in accordance with all of NACE SP0169-2007. Instead, the cathodic protection testing and evaluations shall be performed in accordance with NACE SP0169-2013 (with the exception of Section 6, “Criteria and Other Considerations for Cathodic Protection”). The information from NACE SP0169-2007 will be used instead of NACE SP0169-2013 for Section 6. Per LR-ISG-2015-01, the NRC disagreed with portions of NACE SP0169-2013, Section 6.

Enhancements

The PBN Buried and Underground Piping and Tanks AMP will be enhanced as follows, for alignment with NUREG-2191. This AMP is to be implemented and its inspections and tests begin no earlier than 10 years prior to the SPEO. The inspections and tests are to be completed no later than six months prior to entering the SPEO or no later than the last RFO prior to the SPEO.

Element Affected	Enhancement
2. Preventive Actions	PBN manuals, procedures, etc. will be enhanced to: • State that the cathodic protection system will meet the requirements of GALL SLR Section XI.M41, including the polarized potential criteria of NUREG 2191. PBN takes an exception to the NUREG-2191 requirement of meeting the cathodic protection requirements of NACE SP0169-2007. Instead PBN is committed to meeting the cathodic protection system requirements of NACE SP0169 2013 (with the exception of Section 6, “Criteria and Other Considerations for Cathodic

Element Affected	Enhancement
	Protection"). The information from NACE SP0169 2007 will be used instead of NACE SP0169 2016 for Section 6. Additionally, the cathodic protection system will also include annual system monitoring. • State that new or replaced backfill shall meet the requirements of NACE SP0169-2007 Section 5.2.3 or NACE RP0285-2002, Section 3.6.
3. Parameters Monitored or Inspected	PBN manuals, procedures, etc. will be enhanced to: • Perform visual inspection of the external surfaces of controlled low strength material backfill, where such backfill is used, to detect potential cracks that could admit groundwater to the surface of the component. • Clarify when a volumetric examination should be performed and clarify when pit depth gages or calipers may be used for measuring wall thickness. These techniques may be used as long as: (a) they have been determined to be effective for the material, environment, and conditions (e.g., remote methods) during the examination; and (b) they are capable of quantifying general wall thickness and the depth of pits. • Clarify that cracking inspections for steel utilize a method that has been determined to be capable of detecting cracking. Coatings that: (a) are intact, well-adhered, and otherwise sound for the remaining inspection interval; and (b) exhibit small blisters that are few in number and completely surrounded by sound coating bonded to the substrate do not have to be removed. Inspections for cracking are conducted to assess the impact of cracks on the pressure boundary function of the component. • Clarify that pipe-to-soil potential and the cathodic protection current are monitored for steel piping and tanks in contact with soil to determine the effectiveness of cathodic protection systems.
4. Detection of Aging Effects	PBN manuals, procedures, etc. will be enhanced to: • Clarify that inspections of buried and underground piping and tanks will be conducted in accordance with NUREG-2191 Table XI.M41-2 Category C steel. The inspections will be distributed evenly among the units. Since PBN is a two-unit site, the inspection quantities are 50% greater than NUREG-2191 Table XI.M41-2 and are rounded up to the nearest whole inspection. Thus, the number of inspections for each 10-year inspection period, commencing 10 years prior to the SPEO and continuing during the SPEO, is as follows: • Buried Piping: The smaller of 0.5% of the piping length or two 10-foot segments. • Buried Tank: One inspection for tank T-072. • Underground Tanks: Monitor the annular space of double walled tanks T-175A and T-175B for leakage. When the inspections for a given material type is based on percentage of length and results in an inspection quantity of less

Element Affected	Enhancement
	than 10 feet, then 10 feet of piping is inspected. If the entire run of piping of that material type is less than 10 feet in total length, then the entire run of piping is inspected. • Clarify that the visual inspections will be supplemented with surface and/or volumetric nondestructive testing if evidence of wall loss beyond minor surface scale is observed. • State that PBN site-specific conditions can result in transitioning to a higher number of inspections than originally planned at the beginning of a 10-year interval as specified in NUREG-2192, Section 4.a of XI.M41. • Clarify the guidance for piping inspection location selection as follows: (a) a risk ranking system software incorporates inputs that include coating type, coating condition, cathodic protection efficacy, backfill characteristics, soil resistivity, pipe contents, and pipe function; (b) opportunistic examinations of nonleaking pipes may be credited toward examinations if the location selection criteria are met; and (c) the use of guided wave ultrasonic examinations may not be substituted for the required inspections. • Select one of the alternatives to visual examination of piping from NUREG-2191 pages XI.M41-9 and XI.M41-10. • Clarify that examinations of the buried tank T-072 are conducted from the external surface of the tank using visual techniques or from the internal surface of the tank using volumetric techniques. A minimum of 25% of the buried surface is examined. This area includes at least some of both the top and bottom of the tank. If the tank is inspected internally by volumetric methods, the method must be capable of determining tank wall thickness and general and pitting corrosion and qualified at PBN to identify loss of material that does not meet acceptance criteria. The double wall tanks, T-175A and T-175B shall be examined by monitoring the annular space for leakage.
5. Monitoring and Trending	PBN manuals, procedures, etc. will be enhanced to: • State that for cathodically protected piping, the potential difference and current measurements from the periodic tests are trended by the system engineer to identify changes in the effectiveness of the cathodic protection systems and/or coatings. • Clarify that where wall thickness measurements are conducted, the results will be trended when follow up examinations are conducted. Where practical, all other degradation (e.g., coating condition) will be projected until the next scheduled inspection. • State that inspection and test results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation.

Element Affected	Enhancement
6. Acceptance Criteria	PBN manuals, procedures, etc. will be enhanced to: • For coated piping or tanks, there is either no evidence of coating degradation, or the type and extent of coating degradation is evaluated as insignificant by an individual: (a) possessing a NACE Coating Inspector Program Level 2 or 3 inspector qualification; (b) who has completed the Electric Power Research Institute Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course; or (c) a coatings specialist qualified in accordance with an ASTM standard endorsed in Regulatory Guide 1.54, Revision 2, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.” • Measured wall thickness is evaluated using trend data and projected to continue to meet minimum wall thickness requirements through the end of the SPEO. • No evidence that backfill caused damage to the respective component coatings or the surface of the component (if not coated). • Cracks in cementitious backfill that could admit groundwater to the surface of the component are not acceptable. • Criteria for pipe-to-soil potential when using a saturated copper/copper sulfate (CSE) reference electrode is as stated in NUREG-2191 Table XI.M41-3.
7. Corrective Actions	PBN manuals, procedures, etc. will be enhanced to: • Where damage to the coating has been evaluated as significant and the damage was caused by nonconforming backfill, an extent of condition evaluation is conducted to determine the extent of degraded backfill in the vicinity of the observed damage. • Evaluate the coated and uncoated metallic piping and tanks that show evidence of corrosion to ensure that the minimum wall thickness is maintained throughout the SPEO. This may include different values for large area minimum wall thickness and local area wall thickness. If the wall thickness extrapolated to the end of the SPEO meets minimum wall thickness requirements, the NUREG-2191 Section XI.M41 recommendations for expansion of sample size do not apply. • Where the coatings, backfill, or the condition of exposed piping does not meet acceptance criteria, the degraded condition is repaired or the affected component is replaced. In addition, where the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material is extrapolated to the end of the SPEO, an expansion of sample size is conducted. The number of inspections within the affected piping categories are doubled or increased by five, whichever is smaller. If the acceptance criteria are not met in any of the expanded samples, an analysis is conducted to determine the extent of condition and extent of

Element Affected	Enhancement
	cause. The number of follow-on inspections is determined based on the extent of condition and extent of cause. The timing of the additional examinations is based on the severity of the degradation identified and is commensurate with the consequences of a leak or loss of function. However, in all cases, the expanded sample inspection is completed within the 10-year interval in which the original inspection was conducted or, if identified in the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval. These additional inspections conducted during the 4 years following the end of an inspection interval cannot also be credited towards the required number of inspections for the following 10-year interval. The number of inspections may be limited by the extent of piping or tanks subject to the observed degradation mechanism. The expansion of sample inspections may be halted in a piping system or portion of system that will be replaced within the 10-year interval in which the inspections were conducted or, if identified in the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval.

Operating Experience

Industry Operating Experience

Industry OE shows that buried and underground piping and tanks are subject to corrosion. The critical areas appear to be at the interface where the component transitions from above ground to below ground. This is also the area where coatings and wrappings will most likely be missing or damaged. Corrosion of buried oil, gas, and hazardous materials pipelines have been adequately managed through a combination of inspections and mitigative techniques, such as those prescribed in NACE SP0169-2007 and NACE RP0285-2002. The following industry OE is identified in NUREG-2191:

- In August 2009, a leak was discovered in a portion of buried aluminum pipe where it passed through a concrete wall. The piping is in the condensate transfer system. The failure was caused by vibration of the pipe within its steel support system. This vibration led to coating failure and eventual galvanic corrosion between the aluminum pipe and the steel supports.

- In June 2009, an active leak was discovered in buried piping associated with the condensate storage tank. The leak was discovered because elevated levels of tritium were detected. The cause of the through-wall leaks was determined to be the degradation of the protective moisture barrier wrap that allowed moisture to come in contact with the piping resulting in external corrosion.

- In April 2010, while performing inspections as part of its buried pipe program, a licensee discovered that major portions of their auxiliary feedwater piping were substantially degraded. The licensee's cause determination attributes the cause of the corrosion to the failure to properly coat the piping "as specified" during original construction. The affected piping was replaced during the next refueling outage.

- In November 2013, minor weepage was noted in a 10-inch service water supply line to the emergency diesel generators while performing a modification to a main transformer moat. Coating degradation was noted at approximately 10 locations along the exposed piping. The leaking and unacceptable portions of the degraded pipe were clamped and recoated until a permanent replacement could be implemented.

<u>Plant Specific Operating Experience</u>

The PBN Buried and Underground Piping and Tanks AMP was initially created for the original PBN license renewal, although the buried and underground components were periodically monitored prior to creation of the AMP. Since Units 1 and 2 began operation in 1970 and 1973, respectively, there have been no failures of buried components within the scope of SLR in the service water, fuel oil, or fire protection systems due to external surface degradation.

Documented OE for original license renewal indicated that buried fire protection system piping had been excavated at least seven times since the early 1980s. In each of these cases, no external surface degradation of the buried fire protection system piping was documented.

A recent OE search was performed for SLR which covered a date range of January 1, 2011 through January 1, 2020. This search identified the following action requests related to buried and underground piping and tanks:

- In April 2015, the north fire header at a fire hydrant failed resulting in automatic start of both the electric and diesel fire pumps. This line is composed of 6-inch diameter cement lined, cast iron fire pipe. Excavation of the hydrant revealed the failure was a freeze-induced fracture down the centerline of the fire hydrant. The coating appeared to be in very good condition with no obvious holidays. There was no evidence of external wall loss, and the cement lining appeared to be fully intact throughout the length of the attached pipe. Additionally, there was no evidence of MIC or any other aging mechanism on the interior surface.

- In November 2016, during an opportunistic inspection of the north fire header due to a related fire protection valve replacement, the external condition of the coating was inspected and determined to be intact with no discernable coating thickness loss. The cement lining was intact as well with uniform thickness and no signs of degradation.

In 2015, a survey of the cathodic protection system was performed. A conclusion of this survey was that a majority of the surface to soil potentials did not meet the -850 mV polarized potential criterion. Section 4.2 includes an enhancement repair/upgrade the cathodic protection system.

An effectiveness review of the PBN Buried and Underground Piping and Tanks AMP was performed in 2018 following the guidelines provided in NEI 14-12, Aging Management Program Effectiveness. The effectiveness review covered the applicable ten program elements with particular attention focused on the detection of aging effects (Element 4), corrective action (Element 7), and operating experience (Element 10). The review found that the PBN AMP continues to be effectively implemented although there was a gap related to 50.59 screenings not performed on some changes which has since been addressed.

The commitment for SLR is to perform a fire protection buried piping inspection (excavation) at least every 10 years. Inspections of opportunity can be used to fulfill this commitment. The following is a list of excavations performed over the last 5 years for the fire protection piping as inspections of opportunity.

- April 2015: The north fire header at a fire hydrant was inspected due to freeze induced cracking. This was a 6-inch diameter, cement lined cast iron fire pipe. The external coating appeared to be in very good condition with no obvious holidays and there was no evidence of external wall loss. The internal piping condition was also inspected. The cement lining appeared to be fully intact throughout the length of the pipe and there was no evidence of MIC on the interior surface.

- November 2016: The north fire header was inspected due to a valve replacement. The external condition of the coating was intact with no discernable coating thickness loss. The cement lining was intact as well with uniform thickness and no signs of degradation.

Quarterly health reports for the PBN Buried and Underground Piping and Tanks AMP are reported. The quarterly health reports from January 2015 through February 2020 were reviewed as part of the SLR effort. Generally, the PBN Buried and Underground Piping and Tanks AMP received “green” health reports. There were two quarters a health report was not posted. Additionally, there were quarterly health reports for the cathodic protection system. Most of the cathodic protection system health reports in this timeframe had a “white” score. The latest health report from the first quarter of 2020 acknowledged that the cathodic protection system was past its designed life and was not meeting the NACE criteria. To compensate for the failing cathodic protection system, a modification was added to the long-term asset management (LTAM) program to replace the current cathodic protection system.

The use of AMP effectiveness self-assessments and the relatively high number of AMP revisions shows that the PBN Buried and Underground Piping and Tanks AMP is regularly updated, which is a trait of a healthy AMP. In addition, the plant takes advantage of opportunistic inspections and the inspection results do not show any adverse trends.

In 2010, 2012 and 2013 the NRC performed the 71003 Phase 2 inspections at PBN Units 1 and 2. The inspectors reviewed the AMP as well as a commitment change that required the plant to inspect the susceptible portion of the fire water system (including coated and uncoated/ unwrapped piping). The inspectors reviewed the AMP as well as a commitment change that required the plant to inspect the susceptible (either coated or uncoated/unwrapped) portion of the fire water system.

The reason to include the coated piping in the population of susceptible piping to be inspected was so that the original construction piping would be included. The inspectors noted that the only uncoated buried piping was fire water piping that had been installed within the previous 10 years. The inspectors determined that the AMP and the additional AMP commitment were incorporated into implementing plant procedures. Based on review of the timeliness and adequacy of PBN's actions, the inspectors determined PBN met the commitment related to the PBN Buried and Underground Piping and Tanks AMP. In 2019, the NRC performed the 71003 Phase 4 inspections at PBN Units 1 and 2. Although this inspection reviewed the PBN Buried and Underground Piping and Tanks AMP, it did not identify any relevant OE for the PBN Buried and Underground Piping and Tanks AMP.

The previously referenced NRC inspection reports from 2010, 2012, 2013, and 2019 did not identify any elements in the PBN Buried and Underground Piping and Tanks AMP that would require an enhancement for SLR.

In support of the original license renewal, a review of NRC Inspection Reports, QA Audit/Surveillance Reports and Self Assessments since from 1999 was performed. No issues or findings that could impact the effectiveness of the PBN Buried and Underground Piping and Tanks AMP.

A post-indicating valve was repaired in the fire protection system in June 2002. This repair required the ground to be excavated for valve removal, which exposed buried portions of the valve and fire protection system piping. The piping in the vicinity of the valve was visually inspected. This inspection indicated that piping was coated with a thin tar-like (bituminous asphaltic) coating with some isolated areas where the base metal of the piping was exposed, and the external surface of the piping looked new and with no signs of degradation. The valve and piping were installed in 1988 indicating that the external surface of the piping showed no signs of degradation after being buried for almost 14 years.

In 2009, a section of fire protection piping from original plant construction was excavated and found to have a thick coal tar coating. The coating covered approximately 80 percent of the piping. The exposed piping had very little evidence of corrosion and hardness tests indicated that there was no selective leaching occurring on this section of cast iron pipe. In addition, during the excavation, soil samples taken from the soil in the immediate vicinity of the buried pipe had a resistance of 16,600 ohm-cm supporting the non-aggressive nature of the soil environment.

In 2011, a section of original fire water system ring header piping was excavated to install footings for some above ground components. The section uncovered was the top portion of a 45-degree elbow. The 45-degree elbow was installed with a thin layer of bitumastic coal tar enamel and was in excellent condition. The coating did have some rocks embedded in the coating. Soil samples were tested and indicated that the backfill used in the 6-12 inch range from the Fire Protection header was a drain rock with a minor amount of sand, typically called sandy loam. No hardness tests were performed because no bare pipe was exposed on a susceptible location.

The lack of aging effects is primarily due to preventive measures to mitigate degradation (e.g., external coatings and wrappings and cathodic protection), and the non-aggressive soil conditions at PBN. This is supported by the examples of plant-specific operating experience discussed above. In conclusion, based on the results from NRC inspections and internal self-assessments, and plant specific OE, the PBN Buried and Underground Piping and Tanks AMP provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of SLR are maintained consistent with the CLB during the SPEO.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Buried and Underground Piping and Tanks AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Buried and Underground Piping and Tanks AMP, with exception and enhancements, will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.28 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

Program Description

The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new condition monitoring AMP that has the principal objective to manage the aging effect of loss of coating/lining integrity.

The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP manages degradation of internal coatings/linings exposed to raw water, treated water, treated borated water, waste water, lubricating oil, fuel oil, air, or condensation that can lead to loss of material of base materials or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris. The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is not used to manage loss of coating integrity for external coatings. The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP performs inspections of coatings/linings applied to components which are managed by the PBN Outdoor and Large Atmospheric Metallic Storage Tanks AMP (Section B.2.3.17), the PBN Fuel Oil Chemistry AMP (Section B.2.3.18), the PBN Open-Cycle Cooling Water AMP (Section B.2.3.11), the PBN Closed Treated Water AMP (Section B.2.3.12) and the PBN Fire Water System AMP (Section B.2.3.16).

The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP manages these aging effects for internal coatings by conducting opportunistic and periodic visual inspections of coatings/linings applied to the internal surfaces of in-scope components where loss of coating or lining integrity could impact the component's or downstream component's current licensing basis intended function(s). Where visual inspection of the coated/lined internal surfaces determines the coating/lining is deficient or degraded, physical tests are performed, where physically possible, in conjunction with the visual inspection. The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP uses the following acceptance criteria:

- There are no indications of peeling or delamination.
- Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 (Reference 1.6.69) including staff limitations associated with use of a particular standard. Blisters should be limited to a few intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size or frequency should not be increasing between inspections (e.g., ASTM D714-02, "Standard Test Method for Evaluating Degree of Blistering of Paints").
- Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International

standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard.

- Minor cracking and spalling of cementitious coatings/linings is acceptable provided there is no evidence that the coating/lining is debonding from the base material.

- As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements.

- Adhesion testing results, when conducted, meet or exceed the degree of adhesion recommended in plant-specific design requirements specific to the coating/lining and substrate.

For tanks and heat exchangers, all accessible surfaces are inspected. Piping inspections are sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard. For cementitious coatings/linings inspectors should have a minimum of 5 years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of 1 year of experience. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist with the blisters being surrounded by sound material and with the size and frequency not increasing. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining. Additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment.

Opportunistic inspections, in lieu of periodic inspections, are performed for the buried concrete lined fire protection piping. PBN performs flow tests and internal piping inspections at intervals specified by NUREG-2191, Table XI.M27-1, and is capable of detecting through-wall flaws in the piping through continuous system pressure monitoring (alarm setpoints). In addition, PBN does not have plant-specific OE regarding buried fire main leaks due to age related degradation.

The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will have a new governing and inspection procedure consistent with NUREG-2191, Section XI.M42. Existing procedures that supplement the governing procedure are also required to be updated to ensure that the inspection frequency and sampling criteria are followed, and that in-scope internal coatings are captured.

The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP implementation and pre-SPEO inspections will be completed no later than 6 months prior to the SPEO or no later than the last refueling outage prior to the SPEO. The pre-SPEO inspections will start no earlier than 10 years prior to the SPEO.

NUREG-2191 Consistency

The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be consistent with exceptions with the ten elements of NUREG-2191, Section XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks" as modified by SLR ISG-Mechanical-2020-XX, Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance.

Exceptions to NUREG-2191

The internal coating applied to the T-175A and T-175B EDG Fuel Oil Storage Tanks will be inspected opportunistically as opposed to periodically. This exception is consistent with the PBN Fuel Oil Chemistry AMP, which takes an exception to the requirement to periodically drain, clean, and inspect T-175A and T-175B. The T-175A and T-175B internal coatings will be inspected opportunistically when an internal inspection of the tanks is deemed necessary based on the results of fuel oil sample analysis or as recommended by the system engineer. This exception is justified based on acceptable inspection and wall thickness testing of other fuel oil tanks made of the same material, indicating that no appreciable material loss has occurred in more than 40 years of service as discussed in the Fuel Oil Chemistry AMP. Internal inspections of the buried fuel oil tanks are not required by the plant Technical Specifications. In addition, due to the double wall tank design, regular leak chase monitoring is utilized and such monitoring is capable of identifying through wall leaks. Per ML15127A291, this leak chase monitoring was used as justification for relief from a VT-2 visual inspection normally required by the 2007 Edition with 2008 Addenda of ASME Code, Section XI, Table IWD 2500-1 (Examination Category D-B, Item D2.10). The exterior aging management of these underground tanks is within the scope of the PBN Buried and Underground Piping and Tanks AMP (Section B.2.3.27).

Enhancements

None.

Operating Experience

Industry Operating Experience

The inspection techniques and training of inspection personnel associated with this program are consistent with industry practice and have been demonstrated effective at detecting loss of coating or lining integrity. Not to exceed inspection intervals have been established that are dependent on the results of previous plant-specific inspection results. The following examples describe operating experience (OE) pertaining to loss of coating or lining integrity for coatings/linings installed on the internal surfaces of piping systems:

- During an U.S. Nuclear Regulatory Commission inspection, the staff found that coating degradation, which occurred as a result of weakening of the adhesive bond of the coating to the base metal due to turbulent flow, resulted in the coating eroding away and leaving the base metal subject to wall thinning and leakage (Reference ML12045A544).

- In 1994, a licensee replaced a portion of its cement lined steel service water piping with piping lined with polyvinyl chloride material. The manufacturer stated that the lining material had an expected life of 15–20 years. An inspection in 1997 showed some bubbles and delamination in the coating material at a flange. A 2002 inspection found some locations that had lack of adhesion to the base metal. In 2011, diminished flow was observed downstream of this line. Inspections revealed that a majority of the lining in one spool piece was loose or missing. The missing material had clogged a downstream orifice. A sample of the lining was sent to a testing lab where it was determined that cracking was evident on both the base metal and water side of the lining and there was a noticeable increase in the hardness of the in-service sample as compared to an unused sample. (Reference ML12041A054).

- A licensee has experienced multiple instances of coating degradation resulting in coating debris found downstream in heat exchanger end bells. None of the debris had been large enough to result in reduced heat exchanger performance. (Reference ML12097A064).

- A licensee experienced continuing flow reduction over a 14-day period, resulting in the service water room cooler being declared inoperable. The flow reduction occurred due to the rubber coating on a butterfly valve becoming detached. (Reference ML073200779).

- At an international plant, cavitation in the piping system damaged the coating of a piping system, which subsequently resulted in unanticipated corrosion through the pipe wall. (Reference ML13063A135).

- A licensee experienced degradation of the protective concrete lining which allowed brackish water to contact the unprotected carbon steel piping resulting in localized corrosion. The degradation of the concrete lining was likely caused by the high flow velocities and turbulence from the valve located just upstream of the degraded area. (Reference ML072890132).

- A licensee experienced through-wall corrosion when a localized area of coating degradation resulted in base metal corrosion. The cause of the coating degradation is thought to have been nonage related mechanical damage. (Reference ML14087A210).

- A licensee experienced through-wall corrosion when a localized polymeric repair of a rubber lined spool failed. (Reference ML14073A059).

- A licensee experienced accelerated galvanic corrosion when loss of coating integrity occurred in the vicinity of carbon steel components attached to AL6XN components. (Reference ML12297A333).

The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE including research and development such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

Plant Specific Operating Experience

- Significant Inspections Performed
    - November 2010: A license renewal internal visual inspection of a fuel oil storage tank identified delamination in four areas of the internal coating that was originally applied in 2000. One area of delamination was at the floor-to-plate interface of a vertical structural support member. There were also three delaminations of the coating at different spots along the south wall of the tank, each approximately 1 foot in diameter. The steel in these spots was shiny with no rust and no visible signs of pitting. The coating likely failed due to inadequate surface cleanliness during coating application in these spots (residual oil on the surface). The surrounding coatings exhibited minor cracking near the delaminations but remained intact - attempts to remove additional coating through chipping or scraping were not successful. The remaining coating inside the tank, including the wall areas and tank bottom, appeared to be in excellent condition, with no other signs of delamination or corrosion. Since the rest of the coating was in excellent condition, and the areas of delamination were likely due to inadequate surface preparation, the coating was left as-is and the tank was returned to service. The 10-year internal inspections of the FOSTs are scheduled to be performed in 2020. These internal inspections will provide additional rate-of-degradation information to the PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP.
    - Concrete-lined Fire Protection Piping

      April 2015: The north fire header at a fire hydrant failed resulting in automatic start of both the electric and diesel fire pumps. This line is composed of 6-inch diameter cement lined, cast iron pipe. Excavation of the hydrant revealed the failure was a freeze-induced fracture down the centerline of the fire hydrant. The coating appeared to be in very good condition with no obvious holidays. There was no evidence of external wall loss, and the cement lining appeared to be fully intact throughout the length of the pipe. There was no evidence of MIC on the interior surface or any other aging mechanism.

      November 2016: During an opportunistic inspection at the north fire header related to a valve replacement, the external condition of the coating was inspected and determined to be intact with no discernable coating thickness loss. The cement lining was intact as well with uniform thickness and no signs of degradation.

- Component Cooling Water (CCW) Heat Exchangers – Numerous inspections have been performed of the coatings on the inlets and outlets (raw water side) of the CCW heat exchangers. The results of these inspections are summarized below:

  January 2011, (Shared Unit) ‘B’ CCW heat exchanger: Several small soft spots (similar to a blister but without a bulging appearance) and pits were noted on the inlet cover surface, and on the inlet and outlet channel gasket sealing surfaces. On the inlet cover surface, there were six coating soft spots, each with pits in the steel that appeared to be filled with black MIC material. On the inlet channel gasket surface, small pits in random locations around the circumference were found filled with red rust and/or black MIC material. On the outlet channel gasket surface, three small pits were found which were likewise filled with red rust and black MIC material. The majority of the coated surfaces were intact and in good condition. As a corrective action and preventive measure, coatings were re-applied to the degraded locations prior to returning the heat exchanger to service.

  February 2013, Unit 2 ‘D’ CCW heat exchanger: On the inlet gasket surface, one soft spot (similar to a blister but without a bulging appearance) and small pit were found, as well as three areas of soft spots missing coatings that did not exhibit pitting beneath the soft spots. On the inlet cover, one soft spot and small pit were found. On the outlet gasket surface, four delaminated areas were found within areas recently repaired in the past two cycles. Beneath these soft spots and delamination, the steel was observed to be shiny smooth, without the surface profile/roughness to ensure adequate adhesion. On the outlet cover, two soft spots were found also within areas recently repaired in the past two cycles. The soft spots and pits were each filled with water and black MIC material, which was removed to expose bare shiny steel. The location of degradation at recently repaired areas indicates these issues were associated with improper coatings applications (poor surface profile, lack of sandblasting, etc.).

  June 2013, (Shared Unit) ‘C’ CCW heat exchanger: Two soft spots (similar to a blister but without a bulging appearance) and small pits at the gasket surface were found that needed repair with coating. At the channel to tubesheet transition joint, two minor indications of rust bleeding were found. The coating was tightly adherent, so the condition was considered satisfactory and should be monitored in the future. Excess coating material from a previous repair was also delaminating, which was removed. The inlet cover had no issues. On the outlet gasket surface, five soft spots and small pits were found that that needed repair. The pits were filled with either tan silt, or water and black MIC material, which was removed to expose bare shiny steel. The pits were subsequently weld-repaired and the coating reapplied in order to maintain wall thickness on the covers and gasket sealing surfaces.

  February 2015, (Shared Unit) ‘B’ CCW heat exchanger: On the inlet gasket surface, one soft spot and one pit of were found. The inlet cover and tubesheet were satisfactory. On the outlet gasket surface, additional soft spots and pits were found. The outlet cover had two pits. The soft spots and pits were often filled with water and black MIC material, which was removed to expose bare shiny steel. The pits were then weld-repaired and the coating reapplied in order to maintain wall thickness on the covers and gasket sealing surfaces.

February 2015, Unit 2 ‘D’ CCW heat exchanger: On the inlet gasket surface, three soft spots and pits were found, as well as numerous areas of delaminating coatings with smaller pits. Beneath many of the delaminations (which were most often previously repaired spots), the steel was observed to be shiny smooth, without the necessary roughness to ensure adequate adhesion. On the inlet cover, one soft spot and pit, and four other smaller pits were found. There were also two spots of very thin coating with exposed metal and corrosion but no appreciable loss of metal. On the outlet gasket surface, one small soft spot and pit was found. There were also several delaminations where previous coating repairs had not adhered to the smooth metal surface. On the outlet cover, one soft spot and pit, and numerous other spots of thin coating with exposed metal and corrosion but no appreciable loss of metal were found. The soft spots and pits were often filled with water and black MIC material. The pits were subsequently weld-repaired and the coating reapplied in order to maintain wall thickness on the covers and gasket sealing surfaces.

February 2017, (Shared Unit) ‘B’ CCW heat exchanger: Two significant pits on the gasket and sealing surface were found which required weld repairs. Three other minor pits were also found, which were not as severe. On the outlet channel flange gasket seating surface, small pits as well as delamination of the previously applied coatings was found. The pits were mapped for continued trending and the pits which exceeded acceptance criteria were repaired prior to returning the heat exchanger to service.

June 2017, Unit 1 ‘A’ CCW heat exchanger: On the outlet end, on the channel flange gasket seating surface, two small pits of minor depth were found. The rest of the coating applied to the heat exchanger was in satisfactory condition. Coating repairs were completed to repair the two small pitted locations.

June 2017, (Shared Unit) ‘C’ CCW heat exchanger: The inlet channel flange gasket seating surface had a dozen or more small pits all along the gasket seating surface, several of which exceeded acceptance criteria and required weld repairs. At the inlet end, inside of the channel head flange along the circumference weld as well as the inside surface of the flange itself, soft spots were observed. The degraded coating locations were attributed to improper surface preparation (lack of sandblasting) and repairs were completed to prepare the surface and re-coat the degraded portions of the heat exchanger.

The CCW heat exchangers are periodically inspected to monitor the condition of the internal coatings and will continue to be periodically inspected during the SPEO.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Internal Coatings/Lining for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will provide reasonable assurance that the effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.29 ASME Section XI, Subsection IWE

Program Description

The PBN ASME Section XI, Subsection IWE AMP is an existing AMP that was formerly part of the ASME Section XI, Subsections IWE and IWL Inservice Inspection AMP. This AMP is performed in accordance with ASME Code Section XI, Subsection IWE, and consistent with 10 CFR 50.55a "Codes and Standards," with supplemental recommendations. This program will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC in accordance with 10 CFR 50.55a prior to implementation.

This AMP includes periodic visual, surface, and volumetric examinations, where applicable, of the steel liner of each concrete containment and their integral attachments for signs of degradation, damage, irregularities including discernable liner plate bulges, and for coated areas distress of the underlying metal shell or liner, and corrective actions. Acceptability of inaccessible areas of steel containment shell or concrete containment steel liner is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas.

If site-specific OE identified after the date of issuance of the first renewed license for each unit triggers the requirement to implement a one-time supplemental volumetric examination, then this inspection is performed by sampling randomly selected, as well as focused, liner locations susceptible to corrosion that are inaccessible from one side. The trigger for this one-time examination is site-specific occurrence or recurrence of liner corrosion (base metal material loss exceeding 10 percent of nominal plate thickness) that is determined to originate from the inaccessible (concrete) side. Any such instance would be identified through code inspections performed since 10/05/10 for Unit 1 or 03/08/13 for Unit 2.

Coated surfaces are visually inspected for evidence of conditions that indicate degradation of the underlying base metal. Coatings are a design feature of the base material and are not credited with managing loss of material. The PBN Protective Coating Monitoring and Maintenance AMP (Section B.2.3.36) is used for the monitoring and maintenance of protective containment coatings in relation to reasonable assurance of emergency core cooling system operability. Concrete portions of containments are inspected by the separate PBN ASME Section XI, Subsection IWL AMP (Section B.2.3.30).

Surface conditions are monitored through visual examinations to determine the existence of corrosion. Surfaces are examined for evidence of flaking, blistering, peeling, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, or other signs of surface irregularities. Pressure-retaining bolting is examined for loosening and material conditions that cause the bolted connection to affect either containment leak-tightness or structural integrity. Moisture barriers are visually inspected for degradation per Category E-A.

Cumulative fatigue damage for the PBN liner and piping (and ventilation) penetrations for the containment structures is addressed in the Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis TLAA for SLR (Section 4.6). Cracking due to cyclic loading of non-piping penetrations (hatches, electrical penetrations, etc.) will be managed by the 10 CFR Part 50, Appendix J AMP (Section B.2.3.32) and supplemental surface examinations (or other appropriate examination/evaluation methods) using the ASME Section XI, Subsection IWE AMP. This AMP will also include supplemental one-time inspections within 5 years prior to the SPEO for a representative sample of stainless steel penetrations and dissimilar metal welds that may be susceptible to cracking due to SCC.

Examinations and evaluations are performed in accordance with the requirements of ASME Section XI, Subsection IWE, which provides acceptance standards for the containment pressure boundary components. Areas identified with damage or degradation that exceed acceptance standards require an engineering evaluation or require correction by repair or replacement. Such areas are corrected by repair or replacement in accordance with IWE-3122 or accepted by engineering evaluation.

NUREG-2191 Consistency

The PBN ASME Section XI, Subsection IWE AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S1, “ASME Section XI, Subsection IWE” as modified by SLR-ISG-Structures-2020-XX, Updated Aging Management Criteria for Structures Portions of the Subsequent License Renewal Guidance.

Exceptions to NUREG-2191

None.

Enhancements

The PBN ASME Section XI, Subsection IWE AMP will be enhanced as follows for alignment with NUREG-2191. The one-time inspections for SCC will be started no earlier than five years prior to the SPEO. The enhancements will be implemented and one-time inspections completed no later than six months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Augment existing procedures to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” EPRI TR-104213, “Bolted Joint Maintenance & Application Guide,” and the additional recommendations of NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants.”
2. Preventive Actions	Augment existing procedures to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490

Element Affected	Enhancement
	bolts, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication “Specification for Structural Joints Using ASTM A325 or A490 Bolts,” will be used.
3. Parameters Monitored or Inspected	Augment existing procedures to specify that pressure retaining bolting is inspected for loosening and material condition affecting leak tightness or structural integrity.
4. Detection of Aging Effects	Augment existing procedures to implement periodic supplemental surface examinations (or other appropriate examination/evaluation methods) at intervals no greater than other IWE inspections to detect cracking due to cyclic loading of non-piping penetrations (hatches, electrical penetrations, etc.).
4. Detection of Aging Effects	Augment existing procedures to implement supplemental one-time inspections, performed by qualified personnel using methods capable of detecting cracking due to SCC, comprising (a) a representative sample (two) of the stainless steel penetrations or dissimilar metal welds associated with high-temperature (temperatures above 140°F) stainless steel piping systems in frequent use on each unit; and (b) the stainless steel fuel transfer tube on each unit.
4. Detection of Aging Effects	Augment existing procedures to implement a one-time supplemental volumetric inspection of metal liner surfaces that samples randomly selected as well as focused locations susceptible to loss of thickness due to corrosion from the concrete side if triggered by plant-specific OE identified through code inspections after the date of issuance of the first renewed license for each unit.
7. Corrective Actions	If SCC is detected as a result of the supplemental one-time inspections, additional inspections will be conducted in accordance with the site’s corrective action process.

Operating Experience

Industry Operating Experience

On May 5th, 2014, the NRC issued Information Notice (IN) 2014-07, “Degradation of Leak Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner.” The purpose of this IN was to inform plants of issues identified concerning degradation of floor weld leak-chase channel systems of steel containment shell and concrete containment metallic liner that could affect leak-tightness and aging management of containment structures. The contents of IN 2014-07, as well as the NRC violation report from the Farley event that it discusses, were reviewed by the PBN program owner. While PBN does not have the same configuration of leak chase channel vents as described in the Farley event, the plant does have accessible capped lines for the leak chase. The locations of the leak chase channel vents were documented on applicable PBN drawings and included in IWE visual examinations.

RIS 2016-07, Containment Shell or Liner Moisture Barrier Inspection, was issued on May 9, 2016. PBN has been proactively performing exams on moisture barriers once each Period during the 2nd Interval, and this RIS has been incorporated into the 3rd IWE Interval program plan

These examples provide objective evidence that industry operating experience is being reviewed and evaluated to confirm that station testing procedures are effective to maintain containment integrity.

<u>Plant Specific Operating Experience</u>

Per the requirements of ASME Code Section XI, IWA-6000 and ASME Code Case N-532-5, PBN submits an Owner's Activity Report (OAR) summarizing inservice inspections performed for each outage. OARs from 2014 to 2019 were reviewed for results applicable to IWE with one result. On March 24th, 2017 the bolting for the C-1 Equipment Hatch for Unit 2 was replaced after inspection.

Plant specific operating experience prior to the PEO has shown that containment liner degradation has occurred. For example: degradation has occurred in the Unit 1 and 2 containment liners at the 8-foot elevation due to poor condition of the moisture barriers. The degradation consisted of general corrosion and pitting identified in 2001. The moisture barriers have since been replaced. Degradation of the Unit 1 liner plate due to core drilling and an original construction defect was also identified. In 2001, investigation of corrosion initiated on the accessible side of the liner in the keyway tunnel included core drills into the concrete. Those core drills impacted the bottom of the liner plate, however the originating degradation occurred on the accessible side. Subsequent inspections have not identified degradation occurring on the inaccessible side. The construction defect was a gouge in the liner plate that was covered by the original coating. These were deemed acceptable by engineering evaluation in 1999 and 2001. Several mechanical penetrations inside the Unit 1 and 2 containments have shown indications of general corrosion, pitting in the flued head region, and/or peeling paint. These were deemed acceptable by engineering evaluation in 1998 and 1999. Corrosion was also found in the Unit 1 and 2 Containment Sump A at the interface between the containment liner plates and containment floor slabs. A modification was performed to add a moisture barrier to the concrete to liner interface to arrest further degradation in 1998. In addition, the sump within Sump A had coating degradation at the scum line but no notable material loss.

Similar items continue to be detected during IWE exams, but no on-going degradation mechanisms have been identified, that would question the integrity of containment.

Liner plate monitoring through core holes on the 8-foot elevation and keyway of each containment has shown no significant change over a 10-year period, and therefore the frequency of monitoring was changed. One core hole from each unit will be inspected each Period, and the remaining core holes will be inspected once per Interval.

NRC Post-Approval site Inspections described in License Renewal Phases 2 and 4 Inspection Reports for Units 1 and 2 were reviewed regarding the PBN ASME Section XI, Subsection IWE AMP. This included a review of commitments for each unit, associated with the ASME Code Section XI, Subsections IWE and IWL Inservice Inspection AMP.

The inspectors reviewed the program basis document, implementing procedures, and interviewed the plant personnel responsible for this program. The inspectors verified that these requirements have been incorporated in the program. Based on review of the timeliness and adequacy of PBN actions, the NRC inspectors determined that PBN met commitments in the PBN License Renewal application.

On March 21, 2013, during an NRC inspection of Units 1 and 2, the inspectors identified that PBN failed to define acceptance criteria and incorporate these into the site procedure for containment visual examinations. At the conclusion of the inspection, PBN corrective actions under consideration included: coating the pitted liner areas to stop further corrosion, and development of acceptance criteria for the containment visual examinations. The inspectors also identified inconsistencies in recording relevant conditions documented in the visual examination reports, which could inhibit proper evaluation of containment degradation. PBN entered these documentation inconsistencies into the corrective action program (CAP).

At the conclusion of the inspection, PBN developed visual examination acceptance criteria to restore compliance with this NRC regulation. Because of the very low safety significance and because PBN entered this issue into the CAP, it was treated as an NCV consistent with Section 2.3.2 of the Enforcement Policy.

The quarterly PBN ASME Section XI, Subsection IWE AMP health reports are also developed and trended. All quarterly health reports for 2015 through the first quarter of 2020 demonstrate that the PBN ASME Section XI, Subsection IWE AMP effectively identifies degradation of and evaluates/repairs as necessary the steel liner of each concrete containment and their integral attachments.

The following review of plant-specific OE demonstrates how PBN is managing aging effects associated with the PBN ASME Section XI, Subsection IWE AMP.

- During the Unit 2 Refueling Outage 31 (Spring, 2011) IWE examinations of containment liner plate, areas in the vicinity of the 26-foot elevation equipment hatch were found to have chipped paint and paint removed by what appears to be incidental contact with a grinder. The missing paint was likely the result of past contact with tooling associated with hatch removal / reinstallation and past work on the equipment hatch and hatch flange. Some of the areas with missing paint were showing signs of light rust beginning to form, the affected areas were recoated with a qualified coating during the Unit 2 Refueling Outage 32 (Fall, 2012).

- At PBN, bulges in the liner plate of both units have been observed over the life of the plant. In 7 locations for Unit 1 and 6 locations for Unit 2, "reference bars" (piece of angle iron on brackets) have been installed over the bulged areas so that a profile of each bulge relative to the bar can be measured and trended. No appreciable change has been noted in any of these bulges since the installation of the reference bars.

- Bulges identified during the conduct of more recent examinations for the IWE Program have been evaluated in accordance with requirements. In most instances, the bulged areas have received supplemental ultrasonic thickness (UT) exams to show that the liner plate thickness has not been reduced. In other cases, liner plate bulges were evaluated using qualitative criteria. In all cases, the liner plate bulges were found to be acceptable.

- In response to an industry event where the containment liner plate in the reactor pit area was found to have through-wall defects due to boric acid corrosion, similar concerns were evaluated for PBN. While PBN has had leakage of boric acid from the reactor refueling cavity in the past, inspections conducted in the keyway areas for the IWE, Appendix J, and Containment Coatings programs, as well as the Reactor Coolant System (RCS) system pressure test, should be sufficient to detect boric acid accumulations and allow for corrective actions prior to any significant degradation of the containment liner plate.

- During ASME Section XI IWE walkdowns in October of 2015, boric acid was identified on the intersection of Liner Plates CP-128 and CP-129. The Boric acid was also found on the top of one of the leak chase channel penetrations coming out of the floor. The boric acid was subsequently cleaned.

- In separate instances in 2011, 2012, and 2017, corrosion was discovered at the interface between the liner plate and the concrete floor, either in the keyway or at the 8-foot elevation, for Unit 2. In each case UT testing was performed and the minimum reading for the liner plate was found to be greater than the nominal thickness of 0.250 inches. The Unit 2 keyway was scraped, cleaned, caulked, and painted in 2017.

- In 2017 and 2019, recordable indications on containment moisture barriers were identified for Unit 2 and Unit 1, respectively. In each case, while performing a scheduled ASME Section XI IWE examination, several areas of the moisture barriers were observed to be damaged, missing, or non-adhering at the 8-foot elevation at the interface between the liner plate and the concrete floor. In each case, the moisture barrier was repaired. Observed corrosion was sufficiently superficial that component function would not be impacted.

All instances of corrosion in the above examples originated on the accessible side of the containment liner. These examples demonstrate that the inspections and tests performed under the PBN ASME Section XI, Subsection IWE AMP and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

To assess effectiveness of AMPs credited for subsequent license renewal, the AMPs are reviewed against the criteria provided in NEI 14-12. The most recent effectiveness review of the ASME Section XI, Subsections IWE and IWL Inservice Inspection AMP was performed in 2018. The effectiveness review covered the applicable ten program elements with particular attention on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). The effectiveness review found that this program continues to be effectively implemented.

The positive trending of PBN reviews of the AMP, initiation of corrective actions, and subsequent corrective actions prior to loss of intended function, demonstrates that the PBN ASME Section XI, Subsection IWE AMP remains effective. Additionally, the OE relative to the PBN ASME Section XI, Subsection IWE AMP provides objective evidence that the existing program will effectively monitor and manage aging effect of components within the scope of the AMP.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN ASME Section XI, Subsection IWE AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN ASME Section XI, Subsection IWE AMP will provide reasonable assurance that the aging effects will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.30 ASME Section XI, Subsection IWL

Program Description

The PBN ASME Section XI, Subsection IWL AMP is an existing AMP that was formerly part of the ASME Section XI, Subsections IWE and IWL Inservice Inspection Program. This AMP manages aging of the reinforced concrete containments and unbonded post-tensioning systems and is performed in accordance with ASME Code Section XI, Subsection IWL, and consistent with 10 CFR 50.55a "Codes and Standards," with supplemental recommendations. This program will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC in accordance with 10 CFR 50.55a prior to implementation.

The primary inspection methods specified in this program are visual examinations. General visual exams are employed for the concrete surfaces and tendon anchorage inspections. Selected sample tendon wires are tested for yield strength, ultimate tensile strength, and elongation. Tendon grease is analyzed for alkalinity, water content, and soluble ion concentrations. Pre-stressing forces are measured in select sample tendons under the Concrete Containment Unbonded Tendon Prestress AMP. The Subsection IWL requirements are supplemented to include quantitative acceptance criteria for evaluation of concrete surfaces based on the “Evaluation Criteria” provided in Chapter 5 of ACI 349.3R. Acceptability of inaccessible areas is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas.

Inspection and testing of the steel containment liner and its integral attachments; containment hatches and air locks, seals, gaskets and moisture barriers; and containment pressure retaining bolting are performed by the PBN ASME Section XI, Subsection IWE AMP (Section B.2.3.29) and the PBN 10 CFR Part 50 Appendix J AMP (Section B.2.3.32). Containment tendon prestressing forces are measured and trended as outlined in the Concrete Containment Unbonded Tendon Prestress AMP (Section B.2.2.3).

Final reports are generated for engineering evaluations in accordance with IWL-3300. Inspections that reveal evidence of degradation exceeding the acceptance standards may be subjected to additional inspections to determine the nature and extent of the condition. The degraded condition will be addressed through an engineering evaluation, repair, replacement, or an analytical evaluation in accordance with IWL-3212 and IWL-3213 for concrete and IWL-3222, IWL-3223, and RG 1.35 for post-tensioning systems.

Repair/Replacement Activities are performed in accordance with approved procedures or instructions in accordance with 10 CFR 50.55a, IWA-4000, IWL-4000.

NUREG-2191 Consistency

The PBN ASME Section XI, Subsection IWL AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S2, “ASME Section XI, Subsection IWL.”

Exceptions to NUREG-2191

None.

Enhancements

The following enhancements will be implemented no later than six months prior to entering the SPEO. There are no new inspections to be implemented for SLR.

Element Affected	Enhancement
5. Monitoring and Trending	Augment existing procedures to specify that inspection results be compared to previous results to identify changes from prior inspections, and that quantitative measurements and qualitative information are recorded and trended for applicable parameters monitored or inspected.
6. Acceptance Criteria	Augment existing procedures to specify that inspection results be compared to previous results to determine if degradation is passive for application of second-tier acceptance criteria as specified in ACI 349.3R.

Operating Experience

Industry Operating Experience

Industry operating experience and NRC information notices have documented occurrences of degradation in containment pre-stressing systems

By way of background, ASME Code Section XI, Subsection IWL was incorporated into 10 CFR 50.55a in 1996. Prior to this time, the prestressing tendon inspections were performed in accordance with the guidance provided in RG 1.35, “Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments.” Operating experience (OE) pertaining to degradation of reinforced concrete in concrete containments was gained through the inspections required by 10 CFR 50.55a(g)(4) (i.e., Subsection IWL), 10 CFR Part 50, Appendix J, and inspections conducted by licensees and the NRC. NUREG–1522, “Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures,” described instances of cracked, spalled, and degraded concrete for reinforced and prestressed concrete containments. The NUREG also described cracked anchor heads for the prestressing tendons at three prestressed concrete containments. NRC Information Notice (IN) 99-10, Revision 1, “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containment,” described occurrences of degradation in prestressing systems. IN 2010-14, “Containment Concrete Surface Condition Examination Frequency and Acceptance Criteria,” describes issues concerning the containment concrete surface condition examination frequency and acceptance criteria. The PBN ASME Section XI, Subsection IWL AMP considers the degradation concerns described in these generic communications.

NRC Inspection Report 05000302/2009007 documents OE of an unprecedented delamination event that occurred during a major containment modification of a post-tensioned concrete containment. Although the event is not considered attributable to an aging mechanism, aging characteristics of prestressed concrete containments and lessons learned should be an important consideration for major containment modification repair/replacement activities, especially those involving significant detensioning and retensioning of tendons, during the SPEO.

Plant Specific Operating Experience

Per the requirements of ASME Code Section XI, IWA-6000 and ASME Code Case N-532-5, PBN submits an Owner's Activity Report (OAR) summarizing inservice inspections performed for each outage. OARs from 2014 to 2019 were reviewed for results applicable to IWL with the following results:

Plant specific operating experience has shown that degradation has occurred, including failed tendon wires, missing or broken components found in the tendon hardware, and degraded concrete in containment structure. In addition, industry operating experience and NRC information notices have documented areas of concern regarding concrete and tendon degradation. PBN evaluates these concerns, takes corrective actions as appropriate, and adjusts the program accordingly.

Inspections performed on the containment tendons have discovered broken wires, the presence of nitrates in grease, cracked or missing button-heads, tendon voids in grease volume, and instances of more grease added than removed. These occurrences of degradation have been evaluated and corrective action has been taken, as required.

The 38th year tendon surveillance, performed in 2009, concluded that the Unit 1 and Unit 2 containment structures have experienced no abnormal degradation of their respective post-tensioning systems, are performing in accordance with the design requirements, and are expected to continue to do so. As part of the surveillance, a Unit 2 vertical tendon was tested for lift-off force in order to confirm that tendons located in close proximity to the previously uninsulated main steam penetrations, identified and corrected in 2003, were not affected by the higher localized temperature. The measured lift-off force was acceptable.

The 43rd Year Tendon Surveillance for U1 and U2, completed in 2014, concluded that the containment structures have experienced no abnormal degradation of their respective post-tensioning systems. The containment post-tensioning systems are performing in accordance with the design requirements.

The most recent, 48th Year, Tendon Surveillance was completed in 2019 involving visual (for Unit 1) and physical (for Unit 2) inspections of randomly selected and common tendons. During the Unit 2 inspection, a single hoop tendon was found to have one protruding button-head on one end and a missing button-head on the other end. Both conditions had been previously recorded. It was conservatively assumed that either condition was independent of the other; this reduced the number of assumed effective wires by two for that tendon. However, evaluation of the reported inspection results concluded that the containment structure had experienced no abnormal degradation of the post-tensioning system.

NRC Post-Approval site Inspections described in License Renewal Phases 2 and 4 Inspection Reports for Units 1 and 2 were reviewed for impact on the PBN ASME Section XI, Subsection IWL AMP. None of the items that were identified are relevant to this AMP.

The quarterly PBN ASME Section XI, Subsection IWL AMP health reports are also developed and trended. All quarterly health reports for 2015 through the first quarter of 2020 demonstrate that the PBN ASME Section XI, Subsection IWL AMP effectively identifies degradation of and evaluates/repairs as necessary the reinforced concrete containments and unbonded post-tensioning systems.

The following review of site-specific OE demonstrates how PBN is managing aging effects associated with the PBN ASME Section XI, Subsection IWL AMP.

- During the Unit 2 Tendon Surveillance performed in 2014, the NDE examiner performing a visual examination noted an area of missing concrete. A relatively minor amount of concrete is missing, therefore there is no impact on the ability of the adjacent tendons to perform their function. An engineering review concluded that the spalled area will not prevent the containment from performing its intended function since the condition is not associated with the load bearing/containment tendon portion of the containment structure and that the missing concrete is superficial in nature and does not impact the strength of the containment structure.

- During Unit 1 Tendon Surveillance performed in 2014, a missing button-head on a single wire strand (1 out of 90) was reported. The loss of a single wire strand does not affect the ability of the specific tendon in question to perform its safety function. Since only one wire was affected, this was not a reportable condition. Since the tendon remained acceptable, no further examinations or evaluations were required or taken.

- During Unit 1 Tendon Surveillance performed in 2014, 1 out of 90 wires on a dome tendon was protruding from the bearing surface. Loss of a single wire does not affect the ability of the tendon to perform its safety function. Since only one wire was affected, this was not a reportable condition. Since the tendon remained acceptable, no further examinations or evaluations were required or taken.

These examples demonstrate that the inspections and tests executed under the PBN ASME Section XI, Subsection IWL AMP and the follow-on use of the Corrective Action Program (CAP) are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

To assess effectiveness of AMPs credited for subsequent license renewal, the AMPs are reviewed against the criteria provided in NEI 14-12. The most recent effectiveness review of the ASME Section XI, Subsections IWE and IWL Inservice Inspection Program was performed in 2018. The effectiveness review covered the applicable ten program elements with particular attention on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). The effectiveness review found that this program continues to be effectively implemented. Full AMP effectiveness reviews are performed at least every five years.

The positive trending of PBN reviews of the AMP, initiation of corrective actions, and subsequent corrective actions prior to loss of intended function, demonstrates that the PBN ASME Section XI, Subsection IWL AMP remains effective. Additionally, the OE relative to the PBN ASME Section XI, Subsection IWL AMP provides objective evidence that the existing program will effectively monitor and manage degradation of components within the scope of the AMP.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN ASME Section XI, Subsection IWL AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN ASME Section XI, Subsection IWL AMP will provide reasonable assurance that the aging effects will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.31 ASME Section XI, Subsection IWF

Program Description

The PBN ASME Section XI, Subsection IWF AMP is an existing AMP that consists of periodic visual examination of ASME Code Section XI Class 1, 2, and 3 supports for ASME piping and components for signs of degradation such as corrosion; cracking, deformation; misalignment of supports; missing, detached, or loosened support items; loss of integrity of welds; improper clearances of guides and stops; and improper hot or cold settings of spring supports and constant load supports. Bolting for Class 1, 2, and 3, piping and component supports is also included and inspected for corrosion, loss of integrity of bolted connections due to self-loosening, and material conditions that can affect structural integrity. This program will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC in accordance with 10 CFR 50.55a prior to implementation.

The ASME Section XI, Subsection IWF AMP provides inspection and acceptance criteria and meets the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, 2007 edition with addenda through 2008, and 10 CFR 50.55a(b)(2) for Class 1, 2, and 3 piping and components and their associated supports. The primary inspection method employed is visual examination. NDE indications are evaluated against the acceptance standards of ASME Code Section XI. Examinations that reveal indications are evaluated. Examinations that reveal flaws or relevant conditions that exceed the referenced acceptance standard, are expanded to include additional examinations during the current outage. The scope of inspection for supports is based on sampling of the total support population. The sample size varies depending on the ASME Code Class. The largest sample size is specified for the most critical supports (ASME Code Class 1). The sample size decreases for the less critical supports (ASME Code Class 2 and 3).

This AMP emphasizes proper selection of bolting material, lubricants, and installation torque or tension to prevent or minimize loss of bolting preload of structural bolting and cracking of high strength bolting. As noted below in the enhancement discussion, the AMP also includes the preventive actions for storage requirements of high-strength bolts. The requirements of ASME Code Section XI, Subsection IWF are supplemented to include volumetric examination of high strength bolting for cracking. This AMP will also include a one-time inspection within 5 years prior to the SPEO of an additional 5 percent of piping supports from the remaining IWF population that are considered most susceptible to age-related degradation. Inspections of elastomeric vibration isolation elements to detect hardening are also included if the vibration isolation function is suspect.

NUREG-2191 Consistency

The PBN ASME Section XI, Subsection IWF AMP, with enhancements, will be consistent with one exception to NUREG-2191, Section XI.S3, “ASME Section XI, Subsection IWF.”

Exceptions to NUREG-2191

Inspection of supports for Class MC components under ASME Section XI, Subsection IWF is not required by 10 CFR 50.55a and PBN does not include such inspections in its IWF ISI program. This is an exception to the AMP described in Section XI.S3 of NUREG-2191, whose scope of program addresses Class MC supports. Inspection of the steel containment liner and its integral attachments is included in the scope of the PBN ASME Section XI, Subsection IWE AMP. Applicable portions of the containment polar crane rail supports are inspected under the PBN Inspection of Overhead Heavy Load Handling Systems AMP (Section B.2.3.13), which is currently implemented as part of the PBN Structures Monitoring Program (Section B.2.3.34). Supports for each Unit's Containment dome truss (referred to as the construction truss in the SLR AMR for the Containment Building Structure) and the trusses themselves (which have been lowered from contact with the Containment dome) are inspected under the PBN Structures Monitoring AMP. This represents a continuation of the CLB aging management approach for these components that was approved previously by the staff. Therefore, PBN meets the intent of this NUREG-2191 program element.

Enhancements

The PBN ASME Section XI, Subsection IWF AMP will be enhanced as follows for alignment with NUREG-2191. The one-time inspection will be started no earlier than five years prior to the SPEO. The enhancements will be implemented and one-time inspection completed no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Augment existing procedures to evaluate the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.
1. Scope of Program	Augment existing procedures to include vibration isolation elements of ASME Section XI Class 1, 2, and 3 supports within the ISI Program scope.
2. Preventive Actions	Augment existing procedures to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," and the additional recommendations of NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants."

Element Affected	Enhancement
2. Preventive Actions	Augment existing procedures to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490 bolts, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication “Specification for Structural Joints Using ASTM A325 or A490 Bolts,” will be used.
3. Parameters Monitored or Inspected	Augment existing procedures to specify that bolting within the scope of this program is inspected for loss of integrity of bolted connections due to self-loosening.
3. Parameters Monitored or Inspected	Augment existing procedures to specify that elastomeric or polymeric vibration isolation elements are monitored for cracking, loss of material, and hardening.
4. Detection of Aging Effects	Perform and document a one-time inspection of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation.
4. Detection of Aging Effects	Augment existing procedures to include tactile inspection (feeling, prodding) of elastomeric vibration isolation elements to detect hardening if the vibration isolation function is suspect.
4. Detection of Aging Effects	Augment existing procedures to specify that, for NSSS component supports, high-strength bolting greater than one inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of bolts will be inspected. The sample will be 20% of the population (for a material / environment combination) up to a maximum of 25 bolts.
5. Monitoring and Trending	Augment existing procedures to increase or modify the component support inspection population when a component is repaired to as-new condition by including another support that is representative of the remaining population of supports that were not repaired.
6. Acceptance Criteria	Augment existing procedures to specify that the following conditions are also unacceptable: loss of material due to corrosion or wear; debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support; cracking or sheared bolts, including high-strength bolts, and anchors; loss of material, cracking, and hardening of elastomeric or polymeric vibration isolation elements that could reduce the vibration isolation function; and cracks.

Operating Experience

Industry Operating Experience

Degradation of threaded bolting and fasteners has occurred from boric acid corrosion, SCC, and fatigue loading (U.S. Nuclear Regulatory Commission (NRC) Inspection and Enforcement Bulletin (IEB) 82-02, “Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants,” NRC Generic Letter 91-17, “Generic Safety Issue 79, Bolting Degradation or Failure in Nuclear Power Plants”). SCC has occurred in high-strength bolts used for nuclear steam supply system component supports (EPRI NP-5769). NRC Information Notice 2009-04, ”Age-Related Constant Support Degradation” describes deviations in the supporting forces of mechanical constant supports, from code allowable load deviation, due to age-related wear on the linkages and increased friction between the various moving parts and joints within the constant support, which can adversely affect the analyzed stresses of connected piping systems.

NRC Information Notice 80-36, “Failure of Steam Generator Support Bolting” notified utilities of the potential for stress corrosion cracking (SCC) of high strength component support bolts. High strength (>150 ksi yield) component support bolting is used at PBN in supports associated with NSSS components (i.e., Steam Generator, Reactor Coolant Pump, and Reactor Vessel supports). PBN uses the ISI program to evaluate and monitor crack initiation and growth due to SCC, if present, in high strength low alloy steel bolts used in NSSS component supports.

INPO OE # 312397 described an industry event where control rod drive mechanism (CRDM) Supports were not added to the ISI Program, and IWF exams were not being performed. This OE was reviewed at PBN and found to be applicable to both Units. Examinations of the CRDM supports were performed in the 2014 Fall Outage for Unit 1 and in the 2015 Fall Outage for Unit 2. Exams of the CRDM supports were added to the ISI database to ensure they would be examined in future intervals.

These examples provide objective evidence that industry operating experience is being reviewed and evaluated to confirm that station testing procedures are effective to maintain containment integrity.

Plant Specific Operating Experience

Per the requirements of ASME Code Section XI, IWA-6000 and ASME Code Case N-532-5, PBN submits an Owner’s Activity Report (OAR) summarizing inservice inspections performed for each outage. OARs from 2014 to 2019 were reviewed for results applicable to IWF. The most common relevant condition discovered by the ASME Section XI, Subsection IWF ISI program at PBN has been loose fasteners in supports. To date, these examinations have been effective in managing aging effects for ASME Class 1, 2, and 3 component supports.

NRC Post-Approval site Inspections described in License Renewal Phases 2 and 4 Inspection Reports for Units 1 and 2 were reviewed regarding the PBN ASME Section XI, Subsection IWF AMP. This included a review of commitments for each unit associated with the ASME Code Section XI, Subsection IWF AMP. The inspectors confirmed that the ASME Section XI, Subsection IWF AMP and committed program enhancements were in place.

On June 30th, 2013 and on March 31, 2014, the NRC completed inspections of PBN Units 1 and 2. The resulting integrated inspection reports were reviewed regarding the PBN ASME Section XI, Subsection IWF AMP with no relevant findings identified.

The quarterly PBN ASME Section XI, Subsection IWF AMP health reports are also developed and trended. All quarterly health reports for 2015 through the first quarter of 2020 demonstrate that the PBN ASME Section XI, Subsection IWF AMP has effectively managed aging effects for ASME Class 1, 2, and 3 component supports

The following review of site-specific OE demonstrates how PBN is managing aging effects associated with the PBN ASME Section XI, Subsection IWF AMP.

- During a VT-3 examination of a Unit 1 RHR pipe support in October of 2017, two jam nuts were identified to be missing and the rod between the spring and pipe clamp was misaligned. The condition was reviewed by a structural engineer and noted to be within guidance. Based on an evaluation that the rod was stable, it had not rotated, and there was no mechanism that could cause the threaded rod to unscrew from either fitting the current condition was judged to be acceptable as-is.

- A VT-3 examination of one of the Unit 1 Containment Spray Pumps in August of 2017 noted porosity in one of the welds. The noted porosity was judged to be from original construction, with no observable indications of other damage to the weld. The porosity was not widespread through the weld and the reduction in weld capacity was judged to be minimal. As a result, it was determined that the impact on overall structural integrity would be negligible. The vibration engineer was also consulted, and it was determined that the vibration levels recorded during periodic testing were acceptable with adequate margin. This condition was judged acceptable as-is.

- During as-left VT-3 examination on three Unit 2 RC constant supports in October of 2018, it was noted that the travel indicator on all three supports was not in between the hot and cold positions expected. It was determined that the travel indicator was positioned approximately at the cold marking which was consistent with the plant configuration at the time (Mode 5). As RCS temperature increases, the spray line would displace vertically into the expected range. The supports were judged to remain acceptable and capable of performing intended design functions. No adverse conditions were noted that would indicate any transient occurred for this section of piping.

- During a VT3 examination of the Unit 1 resistance temperature detector (RTD) Bypass Piping Support in April of 2019, a grinding cut was recorded across the horizontal channel, above the diagonal brace. It was noted that there was some paint inside of the grinding cut indicating that it was not new. A calculation related to a previous modification was reviewed and the follow-on field walkdown notes identified damage/insufficient welds as part of the restoration of the removed members to the original configuration and capacity. The noted indication occurred along the horizonal section of channel that was previously removed.

Considering the condition of the connecting welds and associated members, a repair was implemented by welding a plate over the existing damaged members, spanning beyond the cut locations, which was analyzed and demonstrated to serve as an acceptable structural member for the applied loading without taking credit for the damaged components (other than lateral bracing of the plate for buckling concerns). As a result, it was judged that the indication had no effect on the capacity of the support, since the members were still adequate for the purpose of providing lateral bracing to the plate. The support was considered acceptable in the existing configuration

These examples demonstrate that the inspections executed under the PBN ASME Section XI, Subsection IWF AMP and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

To assess effectiveness of AMPs credited for subsequent license renewal, the AMPs are reviewed against the criteria provided in NEI 14-12. The most recent effectiveness review of the ASME Section XI, Subsections IWF AMP was performed in 2018. The effectiveness review covered the applicable ten program elements with particular attention on the detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). The effectiveness review found that this program continues to be effectively implemented. Full AMP effectiveness reviews are performed at least every five years.

The positive trending of PBN reviews of the AMP, initiation of corrective actions, and subsequent corrective actions prior to loss of intended function, demonstrates that the PBN ASME Section XI, Subsection IWF AMP remains effective. Additionally, the OE relative to the PBN ASME Section XI, Subsection IWF AMP provides objective evidence that the existing program will effectively monitor and manage degradation of components within the scope of the AMP.

OE will be reviewed such that if there is an indication that the aging effects are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN ASME Section XI, Subsection IWF AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN ASME Section XI, Subsection IWF AMP will provide reasonable assurance that the aging effects will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.32 10 CFR Part 50, Appendix J

Program Description

The PBN 10 CFR Part 50, Appendix J AMP is an existing AMP that was formerly part of the ASME Section XI, Subsections IWE and IWL Inservice Inspection AMP. The PBN 10 CFR Part 50, Appendix J AMP is a performance monitoring program that monitors the leakage rates through the containment system, its shell or liner, associated welds, penetrations, isolation valves, fittings, and other access openings to detect degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria.

This AMP is implemented in accordance with the 10 CFR Part 50, Appendix J, NEI 94-01 (Reference ML12221A202), "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," and ANSI/ANS 56.8-2002, "Containment System Leakage Testing Requirements." Additionally, this AMP is subject to the requirements of 10 CFR Part 54. PBN technical specifications were updated in 2018 to replace RG 1.163 with NEI 94-01 Revision 3-A and the conditions and limitations specified in NEI 94-01 Revision 2-A as discussed in the Appendix J Testing Program. This AMP credits the existing program required by 10 CFR Part 50, Appendix J.

The PBN containment system consists of a containment structure (containment), and a number of electrical, mechanical, equipment hatch, and personnel air lock penetrations. As described in 10 CFR Part 50, Appendix J, periodic containment leak rate tests are required to ensure that (a) leakage through these containments or systems and components penetrating these containments does not exceed allowable leakage rates specified in the PBN technical specification (TS) and (b) integrity of the containment structure is maintained during its service life. Appendix J of 10 CFR Part 50 provides two options, Option A and Option B, to meet the requirements of a containment leak rate test (LRT) program. PBN uses the performance-based approach, Option B.

The monitored parameters are leakage rates through the containment shell, containment liner, penetrations, associated welds, access openings, and associated pressure boundary components. Three types of tests (Type A, Type B, and Type C) are performed at PBN as specified by 10 CFR Part 50, Appendix J, Option B. Type A integrated leak rate tests (ILRT) determine the overall containment integrated leakage rate, at the calculated peak containment internal pressure related to the design basis loss of coolant accident. Type B (containment penetration leak rate) tests detect local leaks and measure leakage across each pressure-containing or leakage-limiting boundary of containment penetrations. Type C (containment isolation valve leak rate) tests detect local leaks and measure leakage across containment isolation valves installed in containment penetrations or lines penetrating the containment.

Additionally, 10 CFR Part 50, Appendix J, requires a general visual inspection of the accessible interior and exterior surfaces of the containment structures and components to be performed prior to any Type A test and at periodic intervals between tests based on the performance of the containment system. The PBN 10 CFR Part 50, Appendix J AMP meets this requirement with its visual inspection procedures. Additionally, the PBN 10 CFR Part 50, Appendix J AMP inspections may be performed in conjunction with the PBN AMP associated with ASME Code Section XI, Subsections IWE and IWL, to ensure that all evidence of structural deterioration that may affect the containment structure leakage, integrity, or the performance of the Type A test is identified.

When leakage rates do not meet the acceptance criteria, an evaluation is performed to identify the cause of the unacceptable performance and appropriate corrective actions are taken.

NUREG-2191 Consistency

The PBN 10 CFR Part 50, Appendix J AMP will be consistent with the 10 elements of NUREG-2191, Section XI.S4, “10 CFR Part 50, Appendix J.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

NRC Information Notice (IN) 92-20, “Inadequate Local Leak Rate Testing” was issued to alert licensees to problems with local leak rate testing of two-ply stainless steel bellows used on piping penetrations at some plants. Specifically, local leak rate testing could not be relied upon to accurately measure the leakage rate that would occur under accident conditions since, during testing, the two plies in the bellows were in contact with each other, restricting the flow of the local leak rate test medium to the crack locations. Any two-ply bellows of similar construction may be susceptible to this problem. PBN does not have any containment penetration bellows that function as a pressure boundary within the scope of Subsequent License Renewal. Containment bellows are not provided as part of the containment pressure boundary design. All penetrations with bellows are external to containment and are not subject to containment pressure. The fuel transfer tube penetration has bellows with a leak-tight barrier function for refueling water at the refueling cavity and no containment pressure boundary function.

Plant-Specific Operating Experience

At the time the PBN licenses were renewed, a review of plant-specific operating experience revealed failed Appendix J local leak rate tests where previous tests had indicated no adverse trend. For example, a 2-inch check valve failed its local leak rate test as the result of damage to its o-ring soft seal on the valve plunger. The o-ring was replaced, and the valve retested satisfactory. A preventive maintenance activity periodically replaces the o-ring soft seal on this valve. Subsequent performance resulted in the NRC approval of a permanent extension of the Type A test to 15 years, having last been performed in 2011.

NRC Post-Approval site Inspections described in the Phases 2 and 4 License Renewal Inspection Reports for Units 1 and 2 were reviewed regarding the PBN 10 CFR Part 50, Appendix J AMP. No items related to the PBN 10 CFR Part 50, Appendix J AMP were identified in the inspection reports.

The quarterly PBN 10 CFR Part 50, Appendix J AMP health reports are also developed and trended. All quarterly health reports for 2014 through the first quarter of 2020 demonstrate that the PBN 10 CFR Part 50, Appendix J AMP effectively identifies leaking valves, and repairs and retests those valves with satisfactory results. The health reports have been GREEN, with only limited periods of WHITE based on certain Local Leak Rate Tests (LLRT) not meeting acceptance criteria. The valves were repaired and retested as satisfactory. The LLRTs which exceeded acceptance criteria are limited to individual unrelated valves that have been promptly corrected and are not indicative of long-term system degradation. There have not been any inspections, data review, or work order productivity affecting backlogs or equipment or program health. There are no findings, areas for improvement, violations or open issues.

The following review of site-specific OE demonstrates how PBN is managing aging effects associated with the PBN 10 CFR Part 50, Appendix J AMP.

- In April of 2019 while performing containment airlock door seal testing, the Unit 1 Containment airlock inner door exceeded its allowable leakage. Observed leakage averaged 345 standard cubic centimeters per minute (sccm) with an allowable leakage of 200 sccm. An overall containment leakage evaluation was performed and the operable (outer) airlock door was verified closed per the PBN Technical Specifications (TS). The hatch sealing surface was cleaned, and the airlock was retested satisfactorily.

  This issue was entered into the Corrective Action Program (CAP) for trending due for the ARs associated with the containment airlocks. Actions are being implemented to prevent/minimize airlock seal testing issues and based on the latest PBN 10 CFR Part 50, Appendix J AMP health report, procedure changes have been implemented for periodic inspections of the airlock seals.

  This example demonstrates that the inspections and tests executed under the PBN 10 CFR Part 50, Appendix J AMP and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

- Leak testing of penetration 32B, the safety injection test line, performed in October of 2017 indicated a leakage rate greater than 50 percent (680 sccm) of the administrative limit of 1000 sccm. In accordance with the CLRT Testing Program, a work request was issued. No immediate actions were required, because the valve leakage rate met test acceptance criteria.

  This example demonstrates that the inspections and tests executed under the PBN 10 CFR Part 50, Appendix J AMP and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

- Leak testing of containment isolation valve 1RC-528 indicated leakage of 13,428 sccm compared to an administrative limit of 1000 sccm. A review of previous leak test results indicated that the leakage had never exceeded 100 sccm. Based on the leakage rate, the condition was noted as an Appendix J test failure and the valve was marked for repair or replacement. The valve was repaired and tested successfully.

  This example demonstrates that the inspections and tests executed under the PBN 10 CFR Part 50, Appendix J AMP and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

To assess effectiveness of AMPs credited for subsequent license renewal, the AMPs are reviewed against the criteria provided in NEI 14-12. The most recent effectiveness review of the PBN ASME Section XI, Subsections IWE and IWL Inservice Inspection AMP, which included 10 CFR Part 50 Appendix J, was performed in 2018. The effectiveness review covered the applicable ten program elements with particular attention to detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). The effectiveness review found that the 10 CFR Part 50, Appendix J AMP continues to be effectively implemented.

The positive trending of PBN reviews of the AMP, initiation of corrective actions, and subsequent corrective actions prior to loss of intended function, demonstrates that the PBN 10 CFR Part 50, Appendix J AMP remains effective. Additionally, the OE relative to the PBN 10 CFR Part 50, Appendix J AMP provides objective evidence that the existing program will effectively monitor leakage rates through containment systems, its shell or liner, associated welds, penetrations, isolation valves, fittings, and other access openings in order to detect degradation of the containment pressure boundary.

To date, no enhancements to the AMP have been identified as a result of OE. OE will be reviewed such that if there is an indication that the aging effects are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN 10 CFR Part 50, Appendix J AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN 10 CFR Part 50, Appendix J AMP will provide reasonable assurance that the aging effects will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.33 Masonry Walls

Program Description

The PBN Masonry Walls AMP is an existing AMP that was evaluated as a portion of the PBN Structures Monitoring AMP in the initial license renewal application. The PBN Masonry Walls AMP is evaluated separately in the subsequent license renewal application and it is compared to the NUREG-2191, Section XI.S5 program. This AMP consists of inspections based on NRC Inspection and Enforcement (IE) Bulletin 80-11, “Masonry Wall Design,” and NRC Information Notice (IN) 87-67, “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE 80-11,” for managing shrinkage, separation, gaps, loss of material, and cracking of masonry walls, such that the evaluation basis is not invalidated and that the intended functions are maintained.

The PBN Masonry Walls AMP is a condition monitoring program that provides for inspection of masonry walls for loss of material and cracking through monitoring potential shrinkage and/or separation. The AMP will be enhanced to monitor and inspect for shrinkage and/or separation as well as loss of material at the mortar joints and gaps between supports and masonry walls, to include specific monitoring, measurement, and trending of widths and lengths of cracks and of gaps between supports and masonry walls, and to include specific assessment of the acceptability of crack widths and lengths and gaps between supports and masonry walls. The program relies on periodic visual inspections, conducted at a frequency not to exceed five years, to monitor and maintain the condition of masonry walls within the scope of license renewal so that the established design basis for each masonry wall remains valid during the SPEO. Qualifications of inspection and evaluation personnel are in accordance with ACI 349.3R. Unacceptable conditions, when found, are evaluated or corrected in accordance with the corrective action program.

Masonry walls that are fire barriers are also managed by the PBN Fire Protection AMP (Section B.2.3.15).

NUREG-2191 Consistency

The PBN Masonry Walls AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S5, “Masonry Walls.”

Exceptions to NUREG-2191

None.

Enhancements

The following enhancements will be implemented no later than six months prior to entering the SPEO. There are no new inspections to be implemented for SLR.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Revise implementing procedures to also monitor and inspect for spalling, scaling, shrinkage and/or separation as well as loss of material at the mortar joints, and gaps between the supports and masonry walls that could potentially impact the intended function or potentially invalidate its evaluation basis.
5. Monitoring and Trending	Revise implementing procedures to also include specific monitoring, measurement, and trending of widths and lengths of cracks and of gaps between supports and masonry walls.
6. Acceptance Criteria	Revise implementing procedures to also include specific assessment of the acceptability of crack widths and lengths and gaps between supports and masonry walls.

Operating Experience

Industry Operating Experience

Since 1980, masonry walls that perform an intended function have been systematically identified through licensee programs in response to NRC IEB 80-11, NRC Generic Letter 87-02, and 10 CFR 50.48. NRC IN 87-67 documented lessons learned from the NRC IEB 80-11 program and provided recommendations for administrative controls and periodic inspection to provide reasonable assurance that the evaluation basis for each safety-significant masonry wall is maintained. NUREG-1522 documents instances of observed cracks and other deterioration of masonry-wall joints at nuclear power plants. Whether conducted as a stand-alone program or as a part of structures monitoring, a masonry wall AMP that incorporates the recommendations delineated in NRC IN 87-67 provides reasonable assurance that the intended functions of masonry walls within the scope of license renewal are maintained for the SPEO.

Plant Specific Operating Experience

Annual Summary reports are maintained for the Structures Monitoring Program, which includes the inspection and repair activities for masonry walls. These summary reports record conditions requiring evaluation or corrective action by building and status of the corrective action implemented for each degradation. The PBN Structures Monitoring AMP (Section B.2.3.34) contains an overview of the annual summary reports.

The following review of plant-specific OE demonstrates how PBN is managing aging effects associated with the PBN Masonry Walls AMP (Section B.2.3.34).

- In 2011, a crack was identified on the 44’ level of the turbine building block wall and over the staircase. A work request was opened to recommend repair, however an engineering evaluation determined that the cracked wall was not an operability issue. The request was subsequently cancelled.

- In 2016, a roughly half inch wide stair step crack running down the block wall of the turbine building and into a penetration fire seal was identified. The crack was identified as visible from both sides. The cracked Concrete Masonry Unit block was identified as not being a structural wall. A work order to repair the wall was tracked and completed.

- In 2016, degradation of the block wall in the Unit 1/Unit 2 façade was identified during installation of sleeve anchors. The degradation was subjected to an engineering review and determined that the wall would still meet its intended function.

- In 2018, cracked and loose grout was identified in the concrete floor under the stair/platform in the southwest corner of the Unit 1 Non-nuclear Room and the grout under a nearby skid support and under a pipe support on the north side of the Unit 1 Non-nuclear Room during program walkdowns. An engineering evaluation was performed to determine if the block walls remained functional and the degradation was repaired.

The PBN Structures Monitoring AMP has also been enhanced as a result of operating experience. Examples of improvements to the Structures Monitoring Program governing procedure are summarized in SLRA Section B.2.3.34.

OE will be reviewed such that if there is an indication that the aging effects are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Masonry Walls AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Masonry Walls AMP will provide reasonable assurance that the aging effects will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.34 Structures Monitoring

Program Description

The Structures Monitoring Aging Management Program (AMP) is an existing AMP based on the requirements of Title 10 of the Code of Federal Regulations (10 CFR) 50.65 (the Maintenance Rule) and U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.160 (Reference 1.6.70), and Nuclear Management and Resources Council 93-01. These documents provide guidance for development of site/fleet-specific programs to monitor the condition of structures and structural components within the scope of the SLR rule, such that there is no loss of structure or structural component intended function.

The PBN Structures Monitoring AMP consists primarily of periodic visual inspections of plant structures and components (SCs) for evidence of deterioration or degradation, such as described in the American Concrete Institute (ACI) Standards 349.3R, ACI 201.1R, and Structural Engineering Institute/American Society of Civil Engineers Standard (SEI/ASCE) 11. Quantitative acceptance criteria for concrete inspections are based on ACI 349.3R.

Inspections and evaluations are performed by personnel qualified in accordance with GALL-SLR requirements using criteria derived from industry codes and standards contained in the plant CLB including but not limited to ACI 349.3R, ACI 318, SEI/ASCE 11, and the American Institute of Steel Construction (AISC) specifications, as applicable. The AMP includes preventive actions to ensure structural bolting integrity. The program also includes periodic sampling and testing of ground water and the need to assess the impact of any changes in its chemistry on below grade concrete structures.

Included in the program is: inspection of structures, including safety-related buildings and the internal structures within containment; inspection of nonsafety-related structures; inspection of structural steel elements; inspection of elastomers, which includes nonmetallic polymer materials used in seals and gaskets and equipment vibration isolation mounts; and inspection of the component supports commodity group and architectural items.

The earthen berm installed around the above ground fuel oil storage tanks (T-32A and T-32B) is part of the yard structures and is intended to contain fuel oil spills and any resulting fire. This berm is the only earthen structure within the scope of license renewal and is potentially susceptible to degradation caused by surface runoff and erosion.

Coatings minimize corrosion by limiting exposure to the environment. However, coatings are not credited in the determination of aging effects requiring management. Coatings are not credited for license renewal but are used to indicate aging effects of the base material.

Periodic ground water level measurements and chemical analysis of ground/lake water are performed to verify the associated chemistry remains non-aggressive. The frequency of monitoring ground water chemistry (pH, chlorides, and sulfates) is once every 9 months.

NUREG-2191 Consistency

The PBN Structures Monitoring AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S6, “Structures Monitoring.”

Exceptions to NUREG-2191

None.

Enhancements

The following enhancements will be implemented no later than six months prior to entering the SPEO. There are no new inspections to be implemented for SLR.

Element Affected	Enhancement
1. Scope	Update the governing AMP procedure and other applicable procedures to add stainless steel and aluminum as a material that is inspected for pitting and crevice corrosion, and evidence of cracking due to SCC.
2. Preventive Actions	Update the governing AMP procedure and other applicable procedures to include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high strength bolting. Also, ensure proper selection and storage of high strength bolting in accordance with Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High Strength Bolts”.
3. Parameters Monitored or Inspected	Update the governing AMP procedure and other applicable procedures to additionally inspect the following elements: • Concrete Structures will be inspected for increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation. • Elastomer will also be inspected for loss of material and loss of strength. • Pitting and crevice corrosion and evidence of cracking due to SCC for stainless steel and aluminum components • Concrete will be monitored to confirm the absence of water in-leakage
4. Detection of Aging Effects	Update the governing AMP procedure and other applicable procedures to include guidance on inspections for pitting and crevice corrosion, and evidence of cracking due to SCC for stainless steel and aluminum components. Update the governing AMP procedure and other applicable procedures to include guidance on MEB inspection for loss of material (external bus duct enclosure surfaces and

Element Affected	Enhancement
	structural supports) and elastomer degradation (exterior housing gaskets, boots, and sealants). Update the governing AMP procedure and other applicable procedures to clarify that if ground water leakage is identified then engineering evaluation, more frequent inspections, or destructive testing of affected concrete (to validate properties and determine pH) are required. When leakage volumes allow, assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water.
6. Acceptance Criteria	Update the governing AMP procedure and other applicable procedures to include acceptance criteria on inspection of stainless steel and aluminum components for pitting and crevice corrosion, and evidence of cracking due to SCC. In addition, require performance of an evaluation if stainless steel or aluminum surfaces exhibit evidence of SCC, pitting, or crevice corrosion. Update the governing AMP procedure and other applicable procedures to include the following acceptance criteria: • Elastomers: No loss of material and no indications of loss of strength such as unacceptable surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, or hardening. • Bolting and Fasteners: Loose bolts and nuts are not acceptable unless accepted by engineering evaluation. • Structural Sealants: Acceptable if the observed loss of material, cracking, and hardening will not result in loss of sealing.

Operating Experience

Industry Operating Experience

NUREG-1522 documents the results of a survey sponsored in 1992 by the Office of Nuclear Reactor Regulation to obtain information on the types of distress in the concrete and steel SCs, the type of repairs performed, and the durability of the repairs. Information Notice (IN) 2011-20, "Concrete Degradation by Alkali-Silica Reaction” (November 18, 2011) discusses an instance of ground water infiltration leading to alkali-silica reaction degradation in below-grade concrete structures, while IN 2004-05 and IN 2006-13 discusses instances of through-wall water leakage from spent fuel pools. NUREG/CR–7111 provides a summary of aging effects of safety-related concrete structures. There is reasonable assurance that implementation of the structures monitoring program described above will be effective in managing the aging of the in-scope SC supports through the period of subsequent license renewal. No indications of Alkali-Silica Reaction, as discussed in IN 2011-20, have been observed at PBN.

Identified degradation mechanisms are included in the NUREG-2191 Structures Monitoring AMP.

Plant Specific Operating Experience

Annual Summary reports recording degradations and deficiencies by building and status of the corrective action implemented for each degradation have been maintained. A comprehensive report was prepared in 2014 and 2019 summarizing the past five partial annual inspection reports. Year 1 started the enhanced PBN Structures Monitoring AMP in 2010 to Year 5 Structures in 2014. Similarly, the 2019 report reassessed the Year 1 Structures (2014) to Year 5 Structures (2019). Both summary reports concluded that no structures in the scope of license renewal had conditions that would prevent them from meeting their design function requirements.

No signs of physical damage have been observed on the earthen berm around the above ground fuel oil storage tanks, with the exception of animal burrows observed in 2015. In 2015 and 2016, the earthen berm was noted as “Acceptable with Deficiencies” in the annual inspection report. In 2017, repairs were made that replaced the existing earthen berm with underlying concrete mud mat, a new liner, with a geotextile on either side for protection and native soils placed on top of the new liner and seeded.

Site ground water samples have historically tested as non-aggressive. Ground water is tested periodically and recorded in the PBN Chemistry Database.

The PBN Structures Monitoring AMP was selected for evaluation in a 2019 Phase 4 post-approval site inspection. No findings were identified; however, an improvement was suggested to the Facilities Monitoring Program to include signed walkdown sheets, area(s) walked down and any general comments to the work plan, which was then implemented.

To assess effectiveness of AMPs credited for subsequent license renewal, the AMPs are reviewed against the criteria provided in NEI 14-12. The most recent effectiveness review of the PBN Structures Monitoring AMP was performed in 2018. The effectiveness review covered the applicable ten program elements with particular attention to detection of aging effects (element 4), corrective action (element 7), and operating experience (element 10). The effectiveness review found that the Structures Monitoring AMP continues to be effectively implemented

Additionally, FPL corporate engineering performed an assessment on the Nuclear Fleet Structures Monitoring Program in 2018. It concluded that the PBN Structures Monitoring AMP was well organized, and applicable structures continue to meet the program requirements and no significant issues were discovered. There were no gaps in performance identified. However, three recommended enhancements to the annual reports were made.

The following review of site-specific OE demonstrates how PBN is managing aging effects associated with the PBN Structures Monitoring AMP.

- In 2010, a 16-inch diameter hole was bored through one of the 3 ft thick concrete walls that forms the keyway vertical access shaft inside the Unit 1 containment building. The hole is located at the 8 ft elevation of containment. This core bore presented an internal condition of this concrete wall. Thus, an inspection of opportunity was performed, despite the fact that it does not meet the programmatic definition of an Inspection of Opportunity as no normally-underground SSC was exposed. Once the concrete core was removed from the wall it was inspected as was the interior perimeter of the hole in the wall. All of the inspected concrete was found to be in excellent condition with no signs of age-related degradation. Reinforcing steel was cut as part of the core bore and was also found to be in excellent condition.

- In 2013, staining and excessive peeling of the coating of the Steam Dump Stack and staining of the Safety Valve Stack was identified. A work order was generated and subsequently canceled, as the corrosion was considered minor, and would be tracked and trended.

- In 2020, a walkdown identified water dripping from the ceiling along the south wall of the electric shop in the Turbine Building. The cracking noted on the inside and outside of the wall were noted to be relatively narrow cracks from hairline width to approximately 0.010". It was determined that these narrow cracks, with no surficial displacement are typically associated with shrinkage of the concrete during curing and have likely been present for the life of the structure and that there was no challenge to the structure. However, the item is tracked and trended.

The PBN Structures Monitoring AMP has also been enhanced as a result of operating experience. In 2018, an assessment following a margin loss due to the failure of a valve located within the circulating water pump pit identified that programmatic weaknesses existed for inaccessible areas and qualification retrieval. Enhancements were made to specify the required evaluation documentation for inaccessible areas. In 2019, an issue was identified through the Corrective Action program that noted the documentation of the PBN Structures Monitoring AMP evaluation of infrequently accessed radiological areas was not being included in summary reports and that there were areas that had not been inspected on a 5-year frequency due to radiological concerns. The 2014-2019 Facilities Monitoring Report provided a status of these areas in the 5-year program interval and the governing procedure was revised to state “inaccessible areas that are not inspected shall be documented and evaluated as such in the Facilities Monitoring Program inspection report.” Also, in 2019, an improvement was made to add quantitative criteria to the description of a “hairline” crack for more accurate tracking and trending.

OE will be reviewed such that if there is an indication that the aging effects are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Structures Monitoring AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Structures Monitoring AMP will provide reasonable assurance that the aging effects will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.35 Inspection of Water-Control Structures Associated with Nuclear Power Plants

Program Description

The PBN Water-Control Structures AMP is an existing AMP that was evaluated as a portion of the PBN Structures Monitoring AMP (Section B.2.3.34) in the initial license renewal application. The PBN Water Control Structures AMP is evaluated separately in the subsequent license renewal application and it is compared to the NUREG-2191, Section XI.S7 program.

The PBN Water-Control Structures AMP is a condition monitoring program that addresses age-related deterioration, degradation due to environmental conditions, and the effects of natural phenomena that may affect water-control structures. The program is implemented in association with the existing implementing procedure for the Structures Monitoring Program. The structures within the scope of the PBN Water-Control Structures AMP include the forebay and the circulating water pumphouse (CWPH) building. Structural steel and bolting associated with these structures is within the scope of the program inspections. Flood protection features are managed by the Structures Monitoring Program. The PBN Water-Control Structures AMP performs periodic monitoring of water-control structures at least every five years so that the consequences of age-related deterioration and degradation can be prevented or mitigated in a timely manner. Submerged concrete structures are inspected when dewatered or using divers. Areas covered by silt, vegetation, or marine growth are not considered inaccessible and are cleaned and inspected in accordance with the standard inspection frequency. Evaluation of ground water chemistry is performed under the scope of the PBN Structures Monitoring AMP (Section B.2.3.34). The periodic lake water chemical analyses will continue to be performed at least once every 5 years to assure that the below-grade/lake-water environment remains chemically non-aggressive.

The U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” provides detailed guidance for an inspection program for water-control structures, including guidance on engineering data compilation, inspection activities, technical evaluation, inspection frequency, and the content of inspection reports. NRC RG 1.127 delineates current NRC practice in evaluating ISI program for water-control structures. Although PBN is not committed to RG 1.127, this AMP addresses water-control structures, commensurate with the guidance of NRC RG 1.127.

NUREG-2191 Consistency

The PBN Water-Control Structures AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S7, “Inspection of Water-Control Structures Associated with Nuclear Power Plants.”

Exceptions to NUREG-2191

None.

Enhancements

The following enhancements will be implemented no later than six months prior to entering the SPEO. There are no new inspections to be implemented for SLR.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Revise the implementing procedure to also monitor concrete to confirm the absence of water leakage.
4. Detection of Aging Effects	Revise the implementing procedure to include provisions for special inspections immediately following the occurrence of significant natural phenomena, such as large floods, earthquakes, tornadoes, or intense local rainfalls.
4. Detection of Aging Effects	Revise the implementing procedure to clarify that if water leakage is identified, then engineering evaluation, more frequent inspections, or destructive testing of affected concrete (to validate properties and determine pH) are required.
6. Acceptance Criteria	Revise the implementing procedure to indicate that loose bolts and nuts are unacceptable unless they are determined to be acceptable by engineering evaluation or subject to corrective actions.

Operating Experience

Industry Operating Experience

Degradation of water-control structures has been detected, through NRC RG 1.127 programs, at a number of nuclear power plants, and, in some cases, it has required remedial action. NRC NUREG-1522, “Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures” described instances and corrective actions of severely degraded steel and concrete components at the intake structure and pump house of coastal plants. Other degradation described in the NUREG include appreciable leakage from the spillway gates, concrete cracking, corrosion of spillway bridge beam seats of a plant dam and cooling canal, and appreciable differential settlement of the outfall structure of another. No loss of intended functions has resulted from these occurrences. Therefore, it can be concluded that the inspections implemented in accordance with the guidance in NRC RG 1.127 have been successful in detecting significant degradation before loss of intended function occurs.

Plant Specific Operating Experience

Annual Summary reports are maintained for the Structures Monitoring Program, which includes the inspection and repair activities for the CWPH building and forebay. These summary reports record degradations and deficiencies by building and status of the corrective action implemented for each degradation. The PBN Structures Monitoring AMP (Section B.2.3.34) contains an overview of the annual summary reports.

The following review of site-specific OE demonstrates how PBN is managing aging effects associated with the PBN Water-Control Structures AMP.

- In 2013, the roof of the Circulating Water Pumphouse (CWPH) was noted to be in degraded condition. It had been two years since the roof had been routinely inspected. Based on industry OE, it was determined that if degradation continued and a roof leak occurred, it could potentially impact safety related equipment. An inspection was performed, which identified noticeable cracking and weathering of the topcoat of the CWPH roof, but there were no signs of water intrusion on the interior ceiling of the CWPH. The evaluation concluded that there was no operability or functional concern and that the CWPH remained fully operable.

- In 2015, two cracks were found in the northwest corner of the surge chamber near the ice melt valve opening. The cracks were less than 1mm in width and did not penetrate through the depth of the 3-foot or 4-foot thick walls. The evaluation determined that the cracks fell under the second-tier criteria per ACI 349.3R and were deemed acceptable with no further evaluation or repair. The condition was entered into the Structures Monitoring Program to be tracked and trended.

- In 2017, spalled concrete with exposed rebar was observed on the exterior of the CWPH. An evaluation determined that the conditions did not affect the functionality of the structure. A work order to repair the concrete was completed in 2019.

- In 2018, underwater cracks were identified in the forebay walls and floor. An evaluation determined that the identified cracks were existing and had been present for some time. Pressure washing was used to track and clean the crack, which thereby removed some of the spalled concrete, giving the appearance of new cracks. The observations were entered into the Structures Monitoring Program to be tracked and trended, so that the areas will be revisited during future inspections.

The PBN Structures Monitoring AMP has also been enhanced as a result of operating experience. Examples of improvements to the Structures Monitoring Program governing procedure are summarized in SLRA Section B.2.3.34.

OE will be reviewed such that if there is an indication that the aging effects are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Water-Control Structures AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Water-Control Structures AMP will provide reasonable assurance that the aging effects will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.36 Protective Coating Monitoring and Maintenance

Program Description

The PBN Protective Coating Monitoring and Maintenance AMP is an existing AMP that consists of guidance for selection, application, inspection, and maintenance of the Service Level I protective coatings inside the PBN Unit 1 and Unit 2 reactor containment buildings, on both steel and concrete substrates. Maintenance of Service Level I coatings applied to steel surfaces inside containment can reduce loss of material due to corrosion of steel components and aid in decontamination but are not credited for this function. Degraded or unqualified coatings can affect post-accident operability of emergency core cooling systems (ECCS) and therefore, a program to manage aging effects on Service Level I coatings for the Subsequent License Renewal is required.

Proper maintenance of protective coatings inside containment, defined as Service Level I in the NRC Regulatory Guide 1.54, is essential to the operability of post-accident safety systems that rely on water recycled through the containment sump/drain system. Degradation of coatings can lead to clogging of ECCS suction strainers, which reduces flow through the system and could cause unacceptable head loss for the pumps. Regulatory Position C4 in NRC RG 1.54 Revision 3 describes an acceptable technical basis for a Service Level I coatings monitoring and maintenance program. ASTM D 5163-08 and endorsed years of the standard in NRC RG 1.54 Revision 3 are acceptable and considered consistent with NUREG-2191, Section XI.S8.

The PBN Protective Coating Monitoring and Maintenance AMP is a condition monitoring program, with scope that includes Service Level I coatings inside PBN Unit 1 and Unit 2 reactor containment buildings on both steel and concrete substrates. Per the PBN ASME Section XI, Subsection IWE AMP (Section B.2.3.29), coatings are a design feature of the base material and are not credited with managing loss of material.

The PBN Protective Coating Monitoring and Maintenance AMP provides guidelines for the inservice coatings monitoring program for Service Level I coatings in accordance with ASTM D 5163-08. The AMP uses the aging management detection methods, inspector qualifications, inspection frequency, monitoring and trending, and acceptance criteria defined in ASTM D 5163-08, and inspect for any visible defects, such as blistering, crazing, cracking, flaking, peeling, rusting, and physical damage. The inspection frequency for general visual inspections is to be each refueling outage or during other major maintenance outages, as needed. The areas to be inspected and inspection priorities are based on the impact of potential coating failures on plant safety (e.g., proximity to the ECCS sump), previously identified problems or unqualified coatings. The inspection report prioritizes repair areas as either needing repair during the same outage or as postponed to future outages, but under surveillance in the interim period. The assessment from periodic inspections and analysis of total amount of degraded or unqualified coatings in the containment is compared with the total amount of permitted degraded or unqualified coatings to provide reasonable assurance of ECCS operability. Individuals performing follow up inspections shall be trained in applicable reference standards in accordance with ASTM D5498.

The characterization, documentation, and testing of defective or deficient coating surfaces is consistent with ASTM D 5163-08. Additional ASTM and other recognized test methods are available for use in characterizing the severity of observed defects and deficiencies. Assessment reports documenting inspection results are prepared by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, and prioritization of repairs.

NUREG-2191 Consistency

The PBN Protective Coating Monitoring and Maintenance AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.S8, “Protective Coating Monitoring and Maintenance” as modified by SLR-ISG-Structures-2020-XX, Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance.

Exceptions to NUREG-2191

None.

Enhancements

The following enhancements will be implemented no later than six months prior to entering the SPEO. There are no new inspections to be implemented for SLR.

Element Affected	Enhancement
4. Detection of Aging Effects	Enhance existing procedures to specify that follow-up inspections be performed by individuals trained and certified in the applicable reference standards of ASTM Guide D5498.
4. Detection of Aging Effects	Enhance existing procedures to specify that thorough visual inspections shall be carried out on all coatings near sumps or screens associated with the Emergency Core Cooling Systems.
5. Monitoring and Trending	Enhance existing procedures to include coating specifications in the list of pre-inspection documentation available to the inspection team.
10. Operating Experience	Enhance existing procedures to reference guidance of Regulatory Position C.4 of Regulatory Guide 1.54 Revision 3 for Maintenance of Service Level I Coatings.

Operating Experience

<u>Industry Operating Experience</u>

NRC Information Notices, Bulletins and Generic Letters listed in NUREG-2191 describe industry experience pertaining to coatings degradation inside containment and the consequential clogging of sump strainers. In response to these NRC communications, PBN has modified the plant and upgraded plant procedures. NRC Regulatory Guide 1.54, Revision 1, was issued in July 2000. Monitoring and maintenance of Service Level I coatings conducted in accordance with Regulatory Position C4 is expected to be an effective program for managing degradation of Service Level I coatings inside containment. NRC Regulatory Guide 1.54 Revision 2 was issued in October 2010. NRC Regulatory Guide 1.54 Revision 3 was issued in April 2017.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience including research and development such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

Plant Specific Operating Experience

The condition of containment coatings for PBN Units 1 and 2 is assessed each refueling outage in accordance with the PBN coating program procedures. The as-found condition is documented and compared to established acceptance criteria. Any degraded coating conditions are documented and evaluated to determine if repairs are required in the current refueling outage or if the condition should be trended or repaired in future outages. The condition of containment coatings has been found to be acceptable with no significant adverse conditions that would impact emergency core cooling systems (ECCS) operability. Minor repairs have been initiated where warranted to maintain or improve the margins to the design limits with respect to quantity of unqualified and degraded coatings in the containment. For example:

- In April 2017 the inspection of the Unit 2 containment coatings was completed during refuel outage 35. The condition of the containment coatings was found to be acceptable. No immediate corrective actions were required to meet design and license basis requirements. Some desired minor repairs were initiated to improve the material condition and margin with respect to the amount of unqualified coatings in containment. The total quantity of unqualified coatings remained within the bounds required by the design basis calculation with considerable margin remaining.

- In October 2017 the inspection of the Unit 1 containment coatings was completed during refuel outage 37. The condition of the containment coatings was found to be acceptable. No significant findings were identified as compared with the previous containment coating assessment from the Unit 1 refuel outage 36. No immediate corrective actions were required to meet design and license basis requirements. Some desired minor repairs were initiated to improve the material condition and margin with respect to the amount of unqualified coatings in containment. The total quantity of unqualified coatings remained within the bounds required by the design basis calculation with considerable margin remaining.

- In October 2018 the inspection of the Unit 2 containment coatings was completed during refuel outage 36. The condition of the containment coatings was found to be acceptable. No significant findings were identified as compared with the previous containment coating assessment from Unit 2 refuel outage 35. No immediate corrective actions were required to meet design and license basis requirements. Some desired minor repairs were initiated to improve the material condition and margin with respect to the amount of unqualified coatings in containment. The total quantity of unqualified coatings remained within the bounds required by the design basis calculation with considerable margin remaining.

- In April 2019 the inspection of the Unit 1 containment coatings was completed during refuel outage 38. The condition of the containment coatings was found to be acceptable. No significant findings were identified as compared with the previous containment coating assessment from the Unit 1 refuel outage 37. No immediate corrective actions were required to meet design and license basis requirements. Some desired minor repairs were initiated to improve the material condition and margin with respect to the amount of unqualified coatings in containment. The total quantity of unqualified coatings remained within the bounds required by the design basis calculation with considerable margin remaining.

OE will be reviewed such that if there is an indication that the aging effects are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Protective Coating Monitoring and Maintenance AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Protective Coating Monitoring and Maintenance AMP will provide reasonable assurance that the aging effects will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.37 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualifications (EQ) Requirements AMP, previously part of the Cable Conditioning Monitoring Program, is an existing AMP. This AMP provides reasonable assurance that the intended functions of cable and connection electrical insulation exposed to adverse localized environments caused by heat, radiation and moisture can be maintained consistent with the CLB through the SPEO.

This AMP applies to accessible non-EQ electrical cable and connection electrical insulation material within the scope of SLR subjected to adverse (e.g., excessive heat, radiation, and/or moisture) localized environment(s). Adverse localized environments (ALEs) are identified through the use of an integrated approach which includes, but is not limited to, a review of relevant plant-specific and industry OE, a review of EQ zone maps, real-time infrared thermographic inspections, conversations with plant personnel cognizant of specific area and room environmental conditions, etc. To facilitate the identification of an adverse localized environment, a temperature threshold and a radiation threshold will be identified in the plant implementing procedure for cable and connection insulation materials within the scope of this program.

Accessible non-EQ insulated cables and connections within the scope of SLR installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination. The inspection of accessible cable and connection insulation material is used to evaluate the adequacy of inaccessible cable and connection electrical insulation. If visual inspections identify cable jacket and connection insulation surface anomalies, then testing may be performed. A sample population of cable and connection insulation is utilized if testing is performed. The component sampling methodology includes a representative sample of in-scope non-EQ electrical cable and connection types regardless of whether or not the component was included in a previous aging management or maintenance program. The technical basis for the sample selections is documented.

The first inspection for SLR is to be completed no later than six months prior to entering the SPEO. Recurring inspections are to be performed at least once every 10 years thereafter.

Plant-specific OE will be evaluated to identify in-scope cable and connection insulation previously subjected to adverse localized environment during the initial period of extended operation. Cable and connection insulation will be evaluated to confirm that the dispositioned corrective actions continue to support in-scope cable and connection intended functions during the SPEO.

If testing is deemed necessary, a sample of 20 percent of each cable and connection type with a maximum sample size of 25 is tested. Trending actions are not included as part of this AMP. Acceptance criteria under this AMP specifies that no unacceptable visual indications of cable and connection jacket surface anomalies should be observed. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. If testing is deemed necessary, the acceptance criteria for testing electrical cable and connection insulation material is defined in the work order for each cable and connection test and is determined by the specific type of test performed and the specific cable tested.

NUREG-2191 Consistency

The PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

Exceptions to NUREG-2191

None.

Enhancements

The PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be enhanced for alignment with NUREG-2191, as discussed below. This enhanced AMP is to be implemented with inspections completed no later than six months prior to entering the SPEO, or no later than the last refueling outage (RFO) prior to the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Review plant-specific OE for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation during the original PEO. Evaluate to confirm that the dispositioned corrective actions continue to support in-scope cable and connection intended functions during the SPEO.
4. Detection of Aging Effects	If cable testing is deemed necessary, utilize sampling methodology consistent with guidance of Section XI.E1 of NUREG-2191.

Operating Experience

Industry Operating Experience

Industry operating experience (OE) has identified cable and connection insulation aging effects due to adverse localized environments caused by elevated temperature, radiation, or moisture. For example, insulated cables and connections routed next to or above (within 3 feet) steam generators, pressurizers, or hot process pipes, such as feedwater lines may be subjected to an ALE. These environments have been found to cause degradation of electrical cable and connection electrical insulation that are visually observable, such as color changes or surface abnormalities. These visual indications along with cable condition monitoring can be used as indicators of cable and connection insulation degradation.

This industry operating experience resulted in the development and need for this program to ensure that insulated cables and connections, located inside and outside of containment, are not exposed to ALEs that subject the insulated cables and connections to environments that exceed their respective 80-year temperature and radiation limits.

Plant Specific Operating Experience

The following examples of OE provide objective evidence that the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements program will be effective in ensuring that component intended functions are maintained consistent with the CLB during the SPEO.

A review of quarterly system health reports covering the period from the first quarter (Q1) of 2015 through Q1 2020 was conducted to determine program performance during the PEO. The review indicated that the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP has been functioning well during the entire period. Although the overall system health remains green, due to site attrition and the assignment of a new program owner, some areas of the system health report are lower than desired.

From the Q1 2016 Cable System Health Report, the work order planning procedure was revised to ensure hot pipe insulation is reinstalled correctly and that there is no electrical raceway (conduit, cable tray) running over or adjacent to the hot piping. This improvement demonstrates that the program is sensitive to the mitigation of ALEs.

In 2010 and 2013, the NRC examined activities conducted under PBN’s Unit 1 and Unit 2 renewed operating licenses, respectively, as they relate to safety and compliance with the Commission’s rules and regulations under the conditions of the renewed operating licenses. The NRC reviewed the licensing basis, program basis document, implementing procedures, inspection results, and related condition reports (CRs), and interviewed the plant personnel responsible for this AMP. The NRC verified that visual inspections of a representative sample of accessible electrical cables and connections in adverse localized environments had been completed and scheduled in the Periodic Maintenance Program.

Based on the review of the timeliness and adequacy of PBN’s actions, the NRC concluded that program commitments were met.

In 2019, the NRC conducted inspections of select AMPs in accordance with inspection procedure (IP) 71003 - Post-Approval Site Inspection for License Renewal. The team selected seven AMPs for evaluation considering risk insights and programs that were enhanced or new under the renewed operating license. For the AMPs selected, the team reviewed records, interviewed plant staff, and conducted plant walk downs to evaluate whether aging management program elements were being implemented in accordance with NRC requirements.

Based on these inspections, the NRC identified no findings from a review of the PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP documents reviewed.

In 2017, a Self-Assessment was conducted. Although some inconsistencies between plant procedure and fleet procedure were discovered and subsequently corrected, there were no issues related to the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP. This demonstrates that the existing program is continually self-improving.

A search of the action request (AR) database in the corrective action program (CAP) for electrical cable and connections discovered the following:

In July 2010, during a visual inspection of cable trays for License Renewal, there were numerous cables between the cable tray and conduit sleeves that had hard water deposits. The location of the inspection was the Southwest corner of the Unit 1 Facade (the building over the containment) at the 6' 6" level. A review by electrical engineering determined the cable insulation, other than the hard water deposits, had no apparent degradation that would preclude them from performing their intended function. No further action was required.

In October 2015, cracked insulation on a load wire was discovered. The wiring internal to the insulation was intact. The damaged conductor was repaired with a Raychem sleeve in accordance with the Raychem procedure.

In October 2018, cracked wire jacketing was discovered. The jacketing was replaced during an outage in May 2019.

In March 2011, during walkdown of the Unit 2 Containment for License Renewal, an ALE was identified for four cable trays. The stressor identified was heat from one of the main feedwater lines near the cable trays. A visual inspection of cable trays was performed and no abnormal degradation of the cables within the trays was identified.

This plant OE demonstrates the program is effective at identifying adverse localized environments and performing timely inspections of accessible cables and connections within adverse localized environments.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, with enhancements, will provide reasonable assurance that the effects of aging on accessible cables and connections exposed to adverse localized environments (e.g., temperature, radiation, or moisture) will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.38 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits

Program Description

The PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements Used in Instrumentation Circuits AMP, previously part of the Cable Conditioning Monitoring Program, is an existing AMP. This AMP manages the aging effects of the applicable cables and connections in the following systems or sub-systems:

- Nuclear Instrumentation: Excore Source, Intermediate, and Power Range Channels

In most areas within a nuclear power plant the actual operating environment (e.g., temperature, radiation, or moisture) is less severe than the plant design bases environment. However, in a limited number of localized areas, the actual environment may be more severe than the plant design bases environment. These localized areas are characterized as “adverse localized environments” (ALEs) that represent a limited plant area where the operating environment is significantly more severe than the plant design basis environment. An ALE is based on the most limiting environment (e.g., temperature, radiation, or moisture) for the cable or connection insulation.

Exposure of electrical insulation to adverse localized environments caused by temperature, radiation, or moisture can cause age degradation resulting in reduced electrical insulation resistance, moisture intrusion-related connection failures, or errors induced by thermal transients. Reduced electrical insulation resistance causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in electrical insulation resistance is a concern for all circuits, but especially those with sensitive, high-voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation circuits, because a reduced insulation resistance may contribute to signal inaccuracies.

In this AMP, in addition to the evaluation and identification of ALEs, either of two methods can be used to identify the existence of electrical insulation aging effects for cables and connections. In the first method, calibration results or findings of surveillance testing programs are evaluated to identify the existence of electrical cable and connection insulation aging degradation. In the second method, direct testing of the cable system is performed.

Results from the calibrations or surveillances of components within the scope of SLR will be reviewed. The parameters monitored will be determined from the specific calibration, surveillances or testing performed and will be based on the specific instrumentation circuit under surveillance or being calibrated, as documented in plant procedures. Cable testing will be performed on cables in the scope of the program that are disconnected during instrument calibration using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry tests). The parameters for cable testing will be specified in plant procedures. Reviewing the data obtained during normal calibrations or surveillances will allow the detection of severe aging degradation prior to the loss of the cable and connection intended function. The first reviews of calibration or surveillance results for SLR will be completed no later than six months prior to entering the SPEO with ensuing reviews occurring at least once every 10 years thereafter. Calibrations or surveillances that fail to meet acceptance criteria will be reviewed at the time of the calibration or surveillance.

Cable testing is performed by plant procedures on cables within the scope of SLR that are disconnected during instrument calibration. Cable system testing will be performed on the sensitive instrumentation cables that are disconnected during instrument loop calibrations. When the detectors are disconnected during calibrations, these circuits will be tested to determine insulation resistance reduction using tests such as time domain reflectometry or other insulation resistance tests. The first test, using a proven method for detecting deterioration for the insulation system, will be completed no later than six months prior to entering the SPEO with ensuing tests occurring at least once every 10 years thereafter.

Trending actions are not included as part of this AMP because the ability to trend visual inspection and test results is dependent on the test or visual inspection program selected.

In accordance with the PBN CAP, an engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented to ensure that the intended functions of the cables can be maintained consistent with the CLB through the SPEO.

NUREG-2191 Consistency

The PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E2, “Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

Industry operating experience has identified that a change in temperature across a high range radiation monitor cable in containment resulted in a substantial change in the reading of the monitor. Changes in instrument calibration can be caused by degradation of the circuit cable or connection electrical insulation and represents a possible indication of electrical cable degradation.

Plant Specific Operating Experience

The following examples of OE provide objective evidence that the PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits AMP will be effective in ensuring that component intended functions are maintained consistent with the CLB during the SPEO.

- A review of quarterly system health reports covering the period from the first quarter (Q1) of 2015 through Q1 2020 was conducted to determine program performance during the PEO. The review indicated that the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP has been functioning well during the entire period. Although the overall system health remains green, due to site attrition and the assignment of a new program owner, some areas of the system health report are lower than desired.

- In 2010 and 2013, the NRC examined activities conducted under PBN's Unit 1 and Unit 2 renewed operating licenses, respectively, as they relate to safety and compliance with the Commission's rules and regulations under the conditions of the renewed operating licenses.

  The NRC reviewed the licensing basis, program basis document, implementing procedures, inspection results, and related condition reports (CRs), and interviewed the plant personnel responsible for this AMP. The NRC verified that the PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP (previously part of the Cable Conditioning Monitoring Program) met the commitments and were scheduled in the Periodic Maintenance Program.

  Based on the review of the timeliness and adequacy of the PBN's actions, the NRC concluded that program commitments were met.

- In 2019, the NRC conducted inspections of select AMPs in accordance with inspection procedure (IP) 71003 - Post-Approval Site Inspection for License Renewal. The team selected seven AMPs for evaluation considering risk insights and programs that were enhanced or new under the renewed operating license. For the AMPs selected, the team reviewed records, interviewed plant staff, and conducted plant walk downs to evaluate whether aging management program elements were being implemented in accordance with NRC requirements.

  Based on these inspections, the NRC identified no findings from a review of the PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP documents reviewed.

- In 2017, a Self-Assessment was conducted. Although some inconsistencies between site procedure and fleet procedure were discovered and subsequently corrected, there were no issues related to the PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP. This demonstrates that the existing program is continually self-improving.

A search of the action request (AR) database in the CAP for electrical cable and connections discovered the following:

- In November 2012, during safety rail re-installation over the Spent Fuel Pool (SFP), a radiation monitor cable was crushed and caused the meter to display an error message. The condition was determined not to constitute a new degraded or unanalyzed condition that involves the ability of a non-tech spec system, structure or component (SSC) to perform its specified CLB function. The damaged cable was subsequently replaced and re-routed so that the cable did not go through or under the safety rails.

- In March 2014, an excore detector was replaced. Insulation resistance test results of the high-voltage (HV) cable to the replaced detector were anomalous. The connector to the detector was subsequently cleaned and retested satisfactorily.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP provides reasonable assurance that the effects of aging on non-EQ high-voltage, low-level current signal nuclear instrumentation cables (insulation materials) exposed to adverse localized environments (e.g., temperature, radiation, or moisture) will continue to be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.39 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements AMP, previously part of the Cable Conditioning Monitoring Program, is an existing AMP. The purpose of the PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is to provide reasonable assurance that the intended functions of inaccessible medium-voltage (M-V) power cables (operating voltages of 2 kV to 35 kV) that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO.

This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) non-EQ cables within the scope of SLR exposed to wetting or submergence (i.e., significant moisture). Significant moisture is defined as exposure to moisture that lasts more than three (3) days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that occurs for a limited time, as in the case of automatic or passive drainage, is not considered significant moisture for this AMP.

Periodic actions to mitigate inaccessible M-V cable exposure to significant moisture include inspection for water accumulation in cable manholes and conduits and removing water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed no later than six months prior to entering the SPEO. Inspection frequencies are adjusted based on inspection results including site-specific operating experience but with a minimum inspection frequency of at least once annually. Inspections are also performed after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.

Parameters are established for the initiation of an event driven inspection. Inspections include direct indication that cables are not wetted or submerged, and that cable/splices and cable support structures are intact. Dewatering systems (e.g., sump pumps and passive drains) and associated alarms are inspected, and their operation verified periodically. The periodic inspection includes documentation of the effectiveness of either automatic or passive drainage systems, or manually pumping of manholes or vaults, in preventing cable exposure to significant moisture. If water is found inside a manhole during an inspection, dewatering activities are initiated, the source of the water intrusion is determined, and cable degradation is assessed.

Inaccessible non-EQ M-V power cables within the scope of SLR exposed to significant moisture are tested to determine the age degradation of their electrical insulation.

The first tests for SLR are to be completed no later than six months prior to entering the SPEO, with subsequent tests performed at least once every 6 years thereafter.

Submarine or other cables designed for continuous wetting or submergence are also included in this AMP as a one-time inspection and test with additional periodic tests and inspections determined by the one-time test/inspection results as well as industry and site-specific OE. Cable testing depends on the cable type, application, and construction, and typically employs a combination of test techniques capable of detecting reduced insulation resistance or degraded dielectric strength of the cable insulation system due to wetting or submergence. PBN specific inaccessible M-V power cable procedure(s) have been developed to document inspection methods, test methods, and acceptance criteria for the in scope inaccessible power cables based on OE.

An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The acceptance criteria is defined for each cable test and is determined by the specific type of test performed and the specific cable tested. Acceptance criteria for inspections for water accumulation are defined by the direct indication that cable support structures are intact, and cables are not subject to significant moisture. Dewatering systems (e.g., sump pumps and drains) and associated alarms are inspected, and their operation verified to prevent unacceptable exposure to significant moisture.

The aging management of the physical structures, including cable support structures of cable vaults/manholes is managed by the PBN Structures Monitoring AMP (Section B.2.3.34). The PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP scope will be added to existing PBN procedures for governing its surveillance. The existing pertinent procedures will be updated to ensure all aging management activities align with NUREG-2191, Section XI.E3A.

NUREG-2191 Consistency

The PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E3A, “Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements” as modified by SLR-ISG-Electrical-2020-XX, “Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance.”

Regarding draft SLR-ISG-Electrical-2020-XX (Reference ML20156A324), PBN is not taking credit for a continuous water level monitoring system and alarms to extend inspections to five years or to eliminate event driven inspections.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

Operating experience has shown that medium-voltage power cable electrical insulation materials undergo increased degradation either through water tree formation or other aging mechanisms when subjected to significant moisture. Inaccessible medium-voltage power cables subjected to significant moisture may result in an increased age degradation of electrical insulation. Minimizing exposure to significant moisture mitigates the potential for age related degradation. The PBN program is based on the program description in NUREG-2191 XI.E3A, which in turn is based on industry OE.

By way of background, NRC Bulletin 2002-12, issued March 21, 2002, informed licensees of observed submergence in water of electrical cables that feed safety-related equipment. The bulletin detailed accounts of leaking ductbanks, cable jacket tears, and multiple instances of submerged cables in manholes. NRC Generic Letter 2007-01, issued February 7, 2007 further cited NRC Bulletin 2002-12 and informed licensees of these cable failures and asked them to provide information on the monitoring of inaccessible or underground electrical cables. PBN submitted a formal response to NRC Generic Letter 2007-01, under letter NRC 2007-0030 dated May 7, 2007. This documented response, detailed two (2) cable related issues as follows:

- One potential failure was identified. Cable 1A12A is the power cable to circulating water pump 1P-30B. The potential failure was identified when the cable had been deenergized for an extended period of time. Corrective actions included meggering the motor windings and associated power cables (insulation resistance checked to ground) prior to re-energization. Low resistance to ground was measured and subsequent checks isolated the failure in the power cables to the circulating water pump motor. Had the cable been energized at the time, it would have failed.

- In addition, the PBN response detailed the development of a manhole inspection program recognizing the need to keep cables from becoming submerged. The PBN response also provided a detailed listing of underground medium voltage cables that may have degraded by being frequently submerged in water and the test methodologies used to assess their insulation properties. Test and inspection activities are implemented by periodic preventive maintenance activities.

Plant Specific Operating Experience

The following examples of OE provide objective evidence that the PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be effective in ensuring that component intended functions are maintained consistent with the CLB during the SPEO.

A search of the action request (AR) database in the corrective action program (CAP) for underground M-V cables and manholes revealed multiple AR’s during the early implementation of this program (2010-2020 timeframe). The early ARs were primarily used for optimizing manhole inspection frequencies for the original period of extended operation. The early ARs demonstrate that when water inside a manhole was identified at PBN, appropriate corrective actions were taken in a timely fashion in order to keep the cables free from significant moisture. This demonstrates that the program is informed and enhanced through the systematic and ongoing review of plant-specific OE to optimize program performance. As the program has matured, the more recent OE shows a drop in the number of non-programmatically related ARs. This OE confirms that the program periodic actions are effective preventing M-V cables from unacceptable exposure to significant moisture by keeping the water level below the cables jacket.

On 1/15/2008, a failure of the 4.16 kV cabling between Transformer 1X-04 and 4.16 kV Bus 1A-03 occurred as a result of water treeing within the cable insulation, resulting in the lockout of Transformer 1X-04. The degradation was caused by submersion in water over long periods of time due to seals placed in the underground conduits at the Unit 1 Façade wall that prevented drainage of water out of the conduits.

New power cabling was installed between transformer 1X-04 and 4.16 kV buses 1A-03 and 1A-04. The new cabling runs from transformer 1X-04 to the facade in ladder type cable trays with solid covers and supported by a painted steel structure. This new cable routing is all above-ground.

This new cabling has subsequently been added to the program and Tan-Delta testing is performed on a routine basis even though this cabling is now above ground. Test results of the new cabling show no adverse signs of aging degradation. This practice will continue throughout the SPEO.

A review of quarterly system health reports covering the period from the first quarter (Q1) of 2015 through Q1 2020 was conducted to determine program performance during the PEO. The review indicated that the PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP has been functioning well during the entire period. Although the overall system health remains green, due to site attrition and the assignment of a new program owner, some areas of the system health report are lower than desired.

In 2010 and 2013, the NRC examined activities conducted under PBN’s Unit 1 and Unit 2 renewed operating licenses, respectively, as they relate to safety and compliance with the Commission’s rules and regulations under the conditions of the renewed operating licenses.

The commitment for the PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP specified that a representative sample of in-scope, inaccessible non-EQ medium-voltage cables not designed for submergence and subject to significant moisture and significant voltage be tested prior to the end of the current license period and once every ten years during the PEO as part of the AMP.

The NRC reviewed the licensing basis, program basis document, implementing procedures, inspection results, and related condition reports (CRs), and interviewed the plant personnel responsible for this AMP. The NRC verified that testing of a representative sample of in-scope, cables not designed for submergence had been completed and scheduled in the Periodic Maintenance Program.

Based on the review of the timeliness and adequacy of PBN's actions, the NRC concluded that program commitments were met.

In 2019, the NRC conducted inspections of select AMPs in accordance with inspection procedure (IP) 71003 - Post-Approval Site Inspection for License Renewal. The team selected seven AMPs for evaluation considering risk insights and programs that were enhanced or new under the renewed operating license. For the AMPs selected, the team reviewed records, interviewed plant staff, and conducted plant walk downs to evaluate whether aging management program elements were being implemented in accordance with NRC requirements.

Based on these inspections, the NRC identified no findings from a review of the PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP and select M-V cable testing work orders (WOs).

The manholes within the scope of this AMP are visually inspected periodically based on water accumulation over time. Inspection frequencies are adjusted based on inspection results including site-specific OE but with a minimum inspection frequency of at least once annually. Site-specific OE will be used in the adjustment of the inspection frequency of this AMP. The AMP is informed and enhanced as additional site-specific OE is accumulated to ensure cables are kept free from significant moisture.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.40 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The PBN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements AMP is a new AMP for SLR. The purpose of the PBN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is to provide reasonable assurance that the intended functions of inaccessible instrument and control cables that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO.

This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) non-EQ instrumentation and control cables, including those designed for continuous wetting or submergence, within the scope of SLR exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

This is a condition monitoring program. However, periodic actions are taken to prevent inaccessible instrument and control (I&C) cables from being exposed to significant moisture include inspection for water accumulation in cable manholes, vaults, and conduit ends and removing water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspections occur at least once annually with the first inspections for SLR completed no later than prior to entering the SPEO. Additional tests and periodic visual inspections are determined by the test / inspection results and industry and plant-specific aging degradation OE with the applicable cable electrical insulation. The aging management of the physical structures, including cable support structures of cable vaults/manholes, is managed by the PBN Structures Monitoring AMP (Section B.2.3.34).

Inspections for water accumulation are also performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. Parameters are established for the initiation of an event-driven inspection.

Inspections include direct indication that cables are not wetted or submerged, and that cable / splices and cable support structures are intact. Dewatering systems (e.g., sump pumps and passive drains) and associated alarms are inspected, and their operation verified periodically. The periodic inspection includes documentation of the effectiveness of either automatic or passive drainage systems, or manually pumping of manholes or vaults, in preventing cable exposure to significant moisture.

Inaccessible non-EQ I&C cables within the scope of SLR are periodically visually inspected to assess age degradation of the electrical insulation. Inaccessible instrumentation and control cables found to be exposed to significant moisture are evaluated (e.g., a determination is made as to whether a periodic or one-time test is needed for condition monitoring of the cable insulation system). Cable insulation systems that are known via inspection or subsequently found through either industry or plant-specific OE to degrade with continuous exposure to significant moisture (e.g., Vulkene and Raychem cross-linked polyethylene) are also tested to monitor cable electrical insulation degradation over time. The specific type of test(s) will be a proven technique capable of detecting reduced insulation resistance or degraded dielectric strength of the cable insulation system due to wetting or submergence. One or more tests may be required due to cable application, construction, and electrical insulation material to determine the age degradation of the cable insulation. Visual inspection occurs at least once every 6 years with the initial inspection occurring no later than six months prior to entering the SPEO.

In addition to inspecting for water accumulation, a visual inspection of I&C cables accessible from manholes, vaults, or other underground raceways for jacket surface abnormalities is performed. Inspection frequencies are adjusted based on inspection results including plant-specific operating experience.

Cables are periodically visually inspected for cable jacket surface abnormalities such as: embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The cable insulation visual inspection portion of the AMP uses the cable jacket material as representative of the aging effects experienced by the I&C cable electrical insulation. Age degradation of the cable jacket may indicate accelerated age degradation of the electrical insulation due to significant moisture or other aging mechanisms. Visual inspection of inaccessible underground I&C cables also includes a determination as to whether other adverse environments may exist. Cables subjected to these adverse environments are also evaluated for significant aging degradation of the cable insulation system.

The cable testing portion of the AMP utilizes sampling. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. The basis for the methodology and sample used is documented. If an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other inaccessible underground I&C cables not tested and whether the tested sample population should be expanded. The specific type of test(s) determines, with reasonable assurance, in-scope inaccessible I&C cable insulation age degradation. One or more tests may be required due to cable type, application, and electrical insulation to determine the age degradation of the cable insulation. Testing of installed inservice instrumentation and control cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage power cables or low-voltage power cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible instrumentation and control cables when testing is required in this AMP.

Acceptance criteria for inspections for water accumulation are defined by the direct indication that cable support structures are intact, and cables are not subject to significant moisture. Dewatering systems (e.g., sump pumps and drains) and associated alarms are inspected, and their operation verified to prevent unacceptable exposure to significant moisture. Acceptance criterion for visual inspection of cable jackets is no unacceptable signs of surface abnormalities that indicate excessive cable insulation aging degradation may exist. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The acceptance criteria for cable testing (if recommended) are defined for each cable test and are determined by the specific type of test performed and the specific cable tested.

If recommended, initial cable testing is performed once by utilizing sampling to determine the condition of the electrical insulation. Test results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the component intended functions throughout the SPEO based on the projected rate and extent of degradation.

This AMP is to be implemented with inspections completed no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PBN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E3B, “Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements” as modified by SLR-ISG-Electrical-2020-XX, “Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance.”

Regarding draft SLR-ISG-Electrical-2020-XX (Reference ML20156A324), PBN is not taking credit for a continuous water level monitoring system and alarms to extend inspections to five years or to eliminate event driven inspections.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

Industry operating experience shows that this program has proven to be effective at maintaining the intended functions of electrical insulation for non-EQ inaccessible instrumentation and control cables in this program and detecting abnormal conditions such that the condition has been corrected. Therefore, implementation of this new program will provide reasonable assurance that effects of aging will be managed so that components crediting this program can perform their intended function consistent with the CLB during the SPEO.

By way of background, NRC Bulletin 2002-12, issued March 21, 2002, informed licensees of observed submergence in water of electrical cables that feed safety-related equipment. The bulletin detailed accounts of leaking duct banks, cable jacket tears, and multiple instances of submerged cables in manholes. NRC Generic Letter 2007-01, issued February 7, 2007 further cited NRC Bulletin 2002-12 and informed licensees of these cable failures and asked them to provide information on the monitoring of inaccessible or underground electrical cables. PBN submitted a formal response to NRC Generic Letter 2007-01, under letter NRC 2007-0030 dated May 7, 2007. This documented response, detailed two (2) cable related issues as follows:

- One potential failure was identified. Cable 1A12A is the power cable to circulating water pump 1P-30B. The potential failure was identified when the cable had been deenergized for an extended period of time. Corrective actions included meggering the motor windings and associated power cables (insulation resistance checked to ground) prior to re-energization. Low resistance to ground was measured and subsequent checks isolated the failure in the power cables to the circulating water pump motor. Had the cable been energized at the time, it would have failed.
- In addition, the PBN response detailed the development of a manhole inspection program recognizing the need to keep cables from becoming submerged. The PBN response also provided a detailed listing of underground medium voltage cables that may have degraded by being frequently submerged in water and the test methodologies used to assess their insulation properties. Test and inspection activities are implemented by periodic preventive maintenance activities.

<u>Plant Specific Operating Experience</u>

The following examples of OE provide objective evidence that the PBN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will be effective in ensuring that component intended functions are maintained consistent with the CLB during the SPEO.

A search of the action request (AR) database in the corrective action program (CAP) for underground I&C cables and manholes discovered the following:

There were a number of ARs representative of early (2010) instances of water accumulations inside manholes (and submerged cables) at PBN. This prompted PBN to institute a cable program that aggressively addresses and mitigates water levels in manholes, and prevention of long-term significant moisture exposure to all underground cables regardless of voltage level application.

In April 2011, there were several ARs regarding manholes found to have corroded cable supports. These manholes served 4.16 kV, 480 V, 120 VAC and 125 VDC cables. Corrective actions were implemented to inspect for and conduct proper repairs and replacements of the supports. These ARs demonstrate that the site is engaged in the inspections of manhole cable support structures and prompt and effective corrective actions are taken prior to loss of the support structures intended function.

In August 2012, review of the CAP database identified nineteen instances for 2012 where a cable manhole sump alarm had been received. An engineering review of manhole alarm and sump performance in aggregate was performed to determine whether performance was acceptable, or equipment changes were warranted. The review concluded that out of all the events listed, only two events resulted in a condition where cables were actually submerged with all others being pre-emptive alarms.

In November 2014, several issues were found inside a manhole as follows:

- The float associated with the sump pump was stuck.
- A junction box inside the manhole was found full of water.
- An alarm pressure switch was found to be stuck.
- The toggle switch at the top of the manhole which isolates the sump pump was broken.

A work order was developed to perform the following:

- Replace the sump pump with an integral float design.
- Remove two conductors from the junction box and install waterproof Raychem splices.
- Replace the alarm pressure switch.
- Drill a weep hole at the bottom of the conduit to allow it to drain.
- Reconfigure the discharge drain check valve to allow proper drainage of the sump pit.
- Replace the toggle switch at the top of the manhole.

In May 2016, water levels in a manhole were found to have submerged the cables. The water was removed, and as required by plant procedure, megger testing of the I&C cable was performed with no adverse test results noted. This AR demonstrates that ongoing improvements to the existing PBN Cable Condition Monitoring Program, such as testing of cables incurring submergence as a corrective action element, are timely.

The ARs summarized above demonstrate that sump pump performance is closely monitored, trended, and optimized when preventive actions are acquired from plant-specific OE.

The operating experience summarized above demonstrates that the PBN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will be proven to be effective in managing aging effects since it will incorporate proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls. This program is capable of both detecting and trending the aging effects of inaccessible non-EQ instrumentation and control cables (insulation materials) in scope of this program and demonstrates prompt and effective corrective actions prior to a loss of component intended function.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, will provide reasonable assurance that the effects of aging on inaccessible non-EQ instrumentation and controls cables (insulation materials) exposed to an adverse localized environment resulting from significant moisture will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.41 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The PBN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements AMP is a new AMP for SLR. The purpose of the PBN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is to provide reasonable assurance that the intended functions of inaccessible and underground low-voltage ac and dc power cables (i.e., typical operating voltage of less than 1,000 V, but no greater than 2 kV) that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO.

This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) non-EQ low-voltage (L-V) power cables, including those designed for continuous wetting or submergence, within the scope of SLR exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

This is a condition monitoring program. However, periodic actions are taken to prevent inaccessible and underground low-voltage power cables from being exposed to significant moisture include inspection for water accumulation in cable manholes, vaults, and conduits and removing water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspections occur at least once annually with the first inspections for SLR completed no later than prior to entering the SPEO. Additional tests and periodic visual inspections are determined by the test/inspection results and industry and plant-specific aging degradation OE with the applicable cable electrical insulation. The aging management of the physical structures, including cable support structures of cable vaults/manholes, is managed by the PBN Structures Monitoring AMP (Section B.2.3.34).

Inspections include direct indication that cables are not wetted or submerged, and that cable/splices and cable support structures are intact. Dewatering systems (e.g., sump pumps and passive drains) and associated alarms are inspected, and their operation verified periodically. The periodic inspection includes documentation of the effectiveness of either automatic or passive drainage systems, or manually pumping of manholes or vaults, in preventing cable exposure to significant moisture.

Inspections for water accumulation are also performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. Parameters are established for the initiation of an event-driven inspection.

In addition to inspecting for water accumulation, a visual inspection of low-voltage power cables accessible from manholes, vaults, or other underground raceways for jacket surface abnormalities is performed. Inspection frequencies are adjusted based on inspection results including plant-specific operating experience.

Inaccessible low-voltage power cables within the scope of SLR are periodically visually inspected for cable jacket surface abnormalities such as: embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. Visual inspection occurs at least once every 6 years with the initial inspection occurring no later than six months prior to entering the SPEO. The cable insulation visual inspection portion of the AMP uses the cable jacket material as representative of the aging effects experienced by the low-voltage power cable electrical insulation. Age degradation of the cable jacket may indicate accelerated age degradation of the electrical insulation due to significant moisture or other aging mechanisms. Visual inspection of inaccessible and underground low voltage power cables also includes a determination as to whether other adverse environments may exist. Cables subjected to these adverse environments are also evaluated for significant aging degradation of the cable insulation system.

Inaccessible low-voltage power cables found to be exposed to significant moisture are evaluated (e.g., a determination is made as to whether a periodic or one-time test is needed for condition monitoring of the cable insulation system). Cable insulation systems that are known or subsequently found through either industry or plant-specific OE to degrade with continuous exposure to significant moisture (e.g., Vulkene and Raychem cross-linked polyethylene) are also tested to monitor cable electrical insulation degradation over time. The specific type of test(s) will be a proven technique capable of detecting reduced insulation resistance or degraded dielectric strength of the cable insulation system due to wetting or submergence. One or more tests may be required due to cable application, construction, and electrical insulation material to determine the age degradation of the cable insulation.

The cable testing portion of the AMP utilizes sampling. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. The basis for the methodology and sample used is documented. If an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other inaccessible low-voltage power cables not tested and whether the tested sample population should be expanded. The specific type of test(s) determines, with reasonable assurance, in-scope inaccessible low-voltage power cable insulation age degradation. One or more tests may be required based on cable type, application, and electrical insulation material to determine the age degradation of the cable insulation. Testing of installed inservice low-voltage power cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage power cables or instrumentation and control cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible low-voltage power cables when testing is required in this AMP.

Acceptance criteria for water accumulation inspections are defined by the direct indication that cable support structures are intact, and cables/splices are not subject to significant moisture. Dewatering systems (e.g., sump pumps and drains) and associated alarms are inspected, and their operation verified to prevent unacceptable exposure to significant moisture. Acceptance criterion for visual inspection of cable jackets is no unacceptable signs of surface abnormalities that indicate excessive cable insulation aging degradation may exist. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The acceptance criteria for cable testing (if recommended) are defined for each cable test and are determined by the specific type of test performed and the specific cable tested.

If recommended, initial cable testing is performed once by utilizing sampling to determine the condition of the electrical insulation. Test results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the component intended functions throughout the SPEO based on the projected rate and extent of degradation.

This AMP is to be implemented with inspections completed no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PBN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E3C, “Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements” as modified by SLR-ISG-Electrical-2020-XX, “Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance.”

Regarding draft SLR-ISG-Electrical-2020-XX (Reference ML20156A324), PBN is not taking credit for a continuous water level monitoring system and alarms to extend inspections to five years or to eliminate event driven inspections.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

Industry operating experience indicates that cables exposed to significant moisture could have an adverse effect on performance of intended functions or potentially lead to failure of the cable insulation system. The PBN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP is a new AMP based on the program description in NUREG-2191 XI.E3C, which in turn is based on industry OE.

By way of background, NRC Bulletin 2002-12, issued March 21, 2002, informed licensees of observed submergence in water of electrical cables that feed safety-related equipment. The bulletin detailed accounts of leaking duct banks, cable jacket tears, and multiple instances of submerged cables in manholes. NRC Generic Letter 2007-01, issued February 7, 2007 further cited NRC Bulletin 2002-12 and informed licensees of these cable failures and asked them to provide information on the monitoring of inaccessible or underground electrical cables. PBN submitted a formal response to NRC Generic Letter 2007-01, under letter NRC 2007-0030 dated May 7, 2007. This documented response, detailed two (2) cable related issues as follows:

- One potential failure was identified. Cable 1A12A is the power cable to circulating water pump 1P-30B. The potential failure was identified when the cable had been deenergized for an extended period of time. Corrective actions included meggering the motor windings and associated power cables (insulation resistance checked to ground) prior to re-energization. Low resistance to ground was measured and subsequent checks isolated the failure in the power cables to the circulating water pump motor. Had the cable been energized at the time, it would have failed.

- In addition, the PBN response detailed the development of a manhole inspection program recognizing the need to keep cables from becoming submerged. The PBN response also provided a detailed listing of underground medium voltage cables that may have degraded by being frequently submerged in water and the test methodologies used to assess their insulation properties. Test and inspection activities are implemented by periodic preventive maintenance activities.

Plant Specific Operating Experience

The following examples of OE provide objective evidence that the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements program will be effective in ensuring that component intended functions are maintained consistent with the CLB during the SPEO.

A review of quarterly 480 VAC and 125 VDC system health reports covering the period from the first quarter (Q1) of 2015 through Q1 2020 was conducted to determine the health of inaccessible L-V power cables in these systems. The review found no findings related to inaccessible L-V power cables.

Program owner discussions were conducted in February of 2020 to discuss inaccessible L-V power cable plant OE. The Cable Condition Monitoring program owner stated that the plant had begun testing L-V power cables. The plant currently performs insulation resistance (IR) testing to assess the L-V power cables insulation quality. This is not a License Renewal (LR) committed activity. Most of the 480V cables the plant is testing are not inaccessible (i.e. they are not routed underground) and their scope aligns more closely with Maintenance Rule rather than LR or SLR. Based on these discussions, the program owner stated there had been no new / unexpected aging effects experienced.

A search of the action request (AR) database in the corrective action program (CAP) for underground L-V power cables and manholes discovered the following:

In July 2012 while searching for the cause of intermittent grounds on a 480V load center, insulation damage on one cable from a splice/lug from a ground cable was identified. Damage to the insulation was apparent but did not breach through the insulation. The bus was functional and capable of performing its intended function. The cable jacket was subsequently repaired by electrical maintenance.

In January 2016, the Unit 1 facade elevator was reported to be stuck. The hoist way pit had approximately 6" of standing water and the traveling cable had a large cut in the insulation, exposing the white jute wrap underneath. The jute did not appear to be damaged. The water was pumped out of the pit and the cable was repaired by the elevator vendor.

In March 2016, during installation of a new fire seal around the cables associated with a 480V safeguards load center, minor cable jacket damage was noted on one of the 1000 MCM cables. The cable jacket damage likely occurred when the cables were being pulled through the cabinet during installation. The cables were megger tested after installation with acceptable results. Since the risk of damage to the seal is greater than the benefit of adding jacket tape, the cable was left as installed.

In November 2014, several issues were found inside a manhole as follows:

- The float associated with the sump pump was stuck.
- A junction box inside the manhole was found full of water.
- An alarm pressure switch was found to be stuck.
- The toggle switch at the top of the manhole which isolates the sump pump was broken.

A work order was developed to perform the following:

- Replace the sump pump with an integral float design.
- Remove two conductors from the junction box and install waterproof Raychem splices.
- Replace the alarm pressure switch.
- Drill a weep hole at the bottom of the conduit to allow it to drain.
- Reconfigure the discharge drain check valve to allow proper drainage of the sump pit.
- Replace the toggle switch at the top of the manhole.

In April 2011, cable supports inside a manhole were discovered to be were severely corroded. The manhole serviced 4.16 kV, 480V, 120 VAC and 125 VDC cables. The degraded cable supports were replaced.

The operating experience summarized above demonstrates that prompt and effective corrective actions are taken to mitigate inaccessible low-voltage power cable exposure to significant moisture including the inspection for water accumulation in cable manholes, vaults, and conduits by periodic inspections and removing water, as needed prior to a loss of component intended function or failure of the cable insulation system. If required, cable testing will be performed once on a sample population to determine the condition of the electrical insulation.

Based on the OE above, there is reasonable assurance that the effects of aging on L-V inaccessible cable will be managed so that the intended function(s) of components within the scope of this AMP will be maintained consistent with the CLB during the SPEO.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.42 Metal Enclosed Bus

Program Description

The PBN Metal Enclosed Bus AMP is a new AMP (portions of which were previously conducted as part of the Periodic Surveillance and Preventative Maintenance Program (PSPM)). The purpose of the PBN Metal Enclosed Bus (MEB) AMP is to provide reasonable assurance that the intended functions of metal enclosed buses in scope of SLR are maintained consistent with the CLB through the SPEO.

This AMP provides for the inspection of the internal portions of the MEB to be completed prior to the SPEO and conducted every 10 years thereafter. Internal portions (bus enclosure assemblies) of the MEB are inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus electrical insulation material is inspected for signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, or ohmic heating, as indicated by embrittlement, cracking, chipping, melting, discoloration, or swelling, which may indicate overheating or aging degradation. The internal bus insulating supports are inspected for structural integrity and signs of cracks. The external MEB surfaces and structural supports will be inspected prior to the SPEO and conducted every 10 years thereafter under the PBN Structures Monitoring AMP (Section B.2.3.34). The external portions of the MEB, including accessible gaskets, boots, and sealants, are also inspected for hardening or loss of strength due to elastomer degradation that could permit water or foreign debris to enter the bus.

A sample of MEB bolted bus connections will be tested prior to the SPEO and tested every 10 years thereafter to ensure the connections are not experiencing increased resistance due to loosening of bolted bus duct connections caused by repeated thermal cycling of connected loads. A sample of 20 percent with a maximum sample of 25 constitutes a representative bolted bus connection sample size.

MEB external surfaces and structural supports are inspected under the PBN Structures Monitoring AMP (Section B.2.3.34) for loss of material due to general, pitting, and crevice corrosion.

The acceptance criteria of the visual inspections are that MEB electrical insulation materials are free from unacceptable regional indications of surface anomalies such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. MEB internal surfaces show no indications of unacceptable corrosion, cracks, foreign debris, excessive dust buildup, or evidence of moisture intrusion. Accessible elastomers (e.g., gaskets, boots, and sealants) show no indications of unacceptable surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening, and loss of strength. MEB external surfaces are free from unacceptable loss of material due to general, pitting, and crevice corrosion. MEB bolted connections are below the maximum allowed temperature (e.g., comparison of compartment temperatures, trending of temperature over time, or comparison to a baseline thermography signature) for the application when thermography is used or a low resistance value appropriate for the application when resistance measurement is used.

As an alternative to thermography or measuring connection resistance of bolted connections, for accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., PBN may use visual inspection of insulation material to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. When an alternative visual inspection is used to check MEB bolted connections, the first inspection will be completed prior to the SPEO and every 5 years thereafter.

This AMP is to be implemented with inspections completed no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PBN Metal Enclosed Bus AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E4, “Metal Enclosed Bus”.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

Industry experience has shown that failures have occurred on MEBs caused by cracked electrical insulation and moisture or debris buildup internal to the MEB. Experience also has shown that bus connections in the MEBs exposed to appreciable ohmic heating during operation may experience loosening due to repeated cycling of connected loads.

<u>Plant Specific Operating Experience</u>

In March 2010, Point Beach Electrical Maintenance performed License Renewal (LR) visual inspections of the 480V 1B04 to 1B03 Bus Duct. The inspection techniques used involved the detection of signs of bus bar insulation cracking, debris build-up, signs of water intrusions and/or moisture, and discolorations of the bus bars. There was some amount of dust collections on the bus bar. However, there was some slight discoloration of the bus bar due to aging and possible oxidation of the bus bar due to aging effects that did not warrant any remedial action AR. No obvious sign of water intrusion and/or moisture was observed. There was no debris accumulation or foreign matter found in the safeguards bus. The NRC inspector identified that some “PAL locking nuts” were not installed on all fasteners in the bus section. An action request was written to ensure proper installation of locking nuts were restored/conducted.

This demonstrates that the MEB inspections, conducted previously under the PSPM program, have been effective in discovering and correcting improper connections within the MEB, and will continue to be effective under the new PBN MEB Program.

In April 2017, Nuclear Assurance was requested to witness torqueing of cable 2B30AA per a step in the work order on Bus B-04. Hardware configuration was verified for correctness. Nuclear Assurance discovered (2) unused flat washers were on top of the bus bar near the bolted terminal connections. One washer was loose, one washer was clamped under a flat washer that was to be torqued. Craft was notified that there were two extra washers that needed to be removed prior to torqueing. Craft immediately removed the two washers. The crew had been told at shift turnover, that the connections were ready for torqueing.

This demonstrates that the MEB inspections are effective in the discovery and correction of any foreign material exclusion (FME) issues encountered in the prevention of accumulations of FME. These inspection activities, previously under the PSPM program, have been effective in discovering and correcting FME within the MEB enclosures, and will continue to be effective under the new PBN Metal Enclosed Bus Program.

In April 2018, during the performance of a work order for the H-509 switchgear and buswork inspection, it was identified that the insulating material around the bus bar near a 90-degree bend within the back of cubicle H-504-4B had been previously nicked (without being repaired). The tape layers and some of the void fill had been gouged at this nick location. However, there was additional void fill remaining that was still providing insulating properties. It was recommended by the 13.8kV system engineer that an initiated work order (from this condition report) be utilized (after applicable planning) to repair the nick location prior to returning the Gas Turbine (G-05) to service. Additional void fill was required to be inserted within the gouge and the associated tape layers placed over the associated area per Point Beach "Field Taping" procedures / processes. Repair of the nick location was conducted prior to returning the Gas Turbine (G-05) to service.

This demonstrates that the MEB inspections are effective in the discovery and correction of any bus bar insulation abnormalities when encountered. These inspection activities, previously under the PSPM program, have been effective in discovering and correcting insulation abnormalities within the MEB enclosures, and will continue to be effective under the PBN Metal Enclosed Bus Program.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Metal Enclosed Bus AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Metal Enclosed Bus AMP will provide reasonable assurance that the effects of aging on the metal enclosed bus and its internal components will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.43 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The PBN Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements AMP is a new AMP for SLR. The purpose of this AMP is to provide reasonable assurance that the intended functions of the metallic parts of electrical cable connections that are not subject to the EQ requirements of Title 10 of the Code of Federal Regulations (10 CFR) 50.49 and susceptible to age related degradation resulting in increased resistance are maintained consistent with the CLB through the SPEO.

This AMP is a one-time condition monitoring program that manages the aging mechanisms and effects that result in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation of the metallic portions of electrical cable connections within the scope of SLR.

This AMP focuses on the metallic parts of the electrical cable connections. One-time testing, on a sample basis, is performed to confirm the absence of age-related degradation of cable connections resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation. Wiring connections internal to an active assembly are considered part of the active assembly and, therefore, are not within the scope of this AMP. This program does not apply to high voltage (> 35 kV) switchyard connections. Cable connections covered under the EQ program are not included in the scope of this program.

A representative sample of cable connections within the scope of SLR are tested on a one-time test basis to confirm the absence of age-related degradation of the cable connection. Initial one-time test findings will document unacceptable conditions or degradation identified and whether they were determined to be age-related thereby requiring subsequent testing on a 10-year basis. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. One-time testing provides additional confirmation to support industry operating experience (OE) that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective. Depending on the findings of the one-time test, subsequent testing may have to be performed on a ten-year basis. The following factors are considered for sampling: voltage level (medium and low-voltage), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.). Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. The first tests for SLR are to be completed prior to the SPEO.

As an alternative to measurement testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., a visual inspection of insulation materials may be used to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination. When this alternative visual inspection is used to check cable connections, the first inspection is completed prior to the SPEO and at least every 5 years thereafter. The basis for performing only the alternative visual inspection to monitor age-related degradation of cable connections will be documented.

The acceptance criteria for each inspection or test will be defined by the specific type of inspection or test performed for the specific type of cable connection. Cable connections should not indicate abnormal temperatures for the application when thermography is used. Alternatively, connections should exhibit a low resistance value appropriate for the application when resistance measurement is used. When the visual inspection alternative for covered cable connections is used, the absence of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination is suitable in indicating that the covered cable connection components are not loose. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of intended function.

NUREG-2191 Consistency

The PBN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

Electrical cable connections exposed to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation during operation may experience increased resistance of connection. There have been limited numbers of age-related failures of cable connections reported. PBN’s OE with connection reliability and aging effects should be adequate to demonstrate the AMP effectiveness of NUREG-2191 AMP XI.E6, “Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” including the program’s capability to detect the presence or noting the absence of aging effects for electrical cable connections.

The PBN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience.

Plant Specific Operating Experience

A search of plant records showed the following events for the Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements at PBN:

- In May 2010, when performing an inspection of electrical equipment, an upper left cable/stab connection was found to not have a Palnut installed. Site personnel tried to install a Palnut but there was not enough thread on the bolt to allow proper engagement. The upper left cable connection was replaced with bolting of adequate length to allow installation of a Palnut. This was a design and human error issue, and not a cable connection aging issue.

- In January 2011, electrical maintenance (EM) reported cell post to cell post interior cable resistance readings taken on the D-06 Station Battery as follows: Dual posted cells 8 and 9 are connected by two pairs of lugged 3/0 inter tier cables, two lugs per post, and the connection did not meet the Technical Specification minimum value requirements. As a result, the D06 station battery was declared out of service. The resistance readings were taken again with different test equipment and readings were within Technical Specification limits. The connections and system were returned to service. The test equipment used for the initial readings was suspected to be out of calibration.

- In October 2014, a high inter-tier cable connection resistance reading for the gas turbine generator 125V DC Battery was measured. There were two intercell connections with resistance readings greater than that allowed by procedure. An initial review by engineering determined that although the resistance was higher than allowed, there was sufficient margin (demonstrated by battery discharge testing) such that the increased resistance connection would not result in a condition where the battery would not be able to perform its function to supply loads to the gas turbine generator. No further action or rework was required.

- In October 2014, a temperature indicator had erratic indications with the indication dropping intermittently down to as low as about 120 °F and returning to its expected full power nominal indication of about 569 °F. The erratic Indication was consistent with a core exit thermocouple (CET) head connector issue. Troubleshooting performed as part of CET replacement during the following refueling outage determined the issue to be a damaged transition cable connector. Intermittent shorts were occurring at the connector between the thermocouple leads and the thermocouple leads and the transition cable sheath. As a result, the cable/connection was replaced during the outage. The connection damage appeared to be mechanical and not a connection metallic aging issue.

- In June 2015, an Optical Emission Spectroscopy (OES) instrument was having intermittent connection issues with the plant computer based on error codes on software displaying "IEEE cable connections". A corrective action was assigned to the chemistry department to track vendor repair of the OES instrument. The vendor determined the OES was functional and that the power outlet to the OES was supplying power at a lower voltage than recommended for the instrument. Electrical maintenance measured, troubleshooted, and repaired the power supply outlet voltage. The issue appeared to be due to excessive manual manipulations and not related to aging.

- In January 2017, cable connections associated with an incore thermocouple that had been out of service since 2005 were investigated. Although the temperature readings had been relatively close to expected values, testing performed in August 2016 suggested a current path existed between signal and shield. The cable/connection was replaced. The issue appeared to be a loss of insulation capability (short) and did not reflect an aging issue on the metallic portion of the connection.

- In April 2017, a flow instrument signal converter cable connector was found cracked during calibration. The outer plastic on the connector was replaced and the calibration was completed satisfactorily. The cracked portion provided an insulation function and did not reflect an aging issue of the metallic portion of the connection.

In 2017, Point Beach 1 – Plant Inspection Findings identified an OE evaluation oversight whereby cable connections became disconnected due to machine vibration. Specifically, a disconnected magnetic speed sensor cable on the G-04 emergency diesel generator (EDG) caused a failure during a surveillance run attempt. The Fix-It-Now (FIN) team conducted short-term corrective actions that involved reconnecting the G-04 EDG magnetic speed senor cable and installing a lock-wire to prevent the connector from unintentionally disconnecting. PBN's long-term corrective actions included changing maintenance procedures to check connector tightness on the diesels periodically.

This was a very localized connection issue specific to an instrument cable either not being properly tightened, or subject to an extreme vibration environment, or both. Both the short-term and long-term solutions have proven effective in preventing any subsequent loosening of the cable connection.

The new PBN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP program health report is presently ascertained through the existing 120VAC, 125V, 480V, 4160V, and 19kV system health reports, which are updated quarterly.

The system health reports for the 125V, 480V and 4160V voltage systems have shown green for the five most recent quarters. The first of two electrical connection issues involved high connection resistances on two battery connections. Causes were not identified and initial corrective action attempts (e.g. cleaning, retightening) were not successful to attain acceptable resistance results. The connections were replaced. The second involved an outdoor transformer cabinet. The transformer cabinet is original plant equipment supplied by Westinghouse and periodically experiences internal moisture/corrosion due to its age and service environment. Corroded terminations internal to the transformer cabinet have been identified and cleaned to ensure proper electrical continuity. Inspections of the transformer cabinet are performed on a monthly basis. The connections inside the transformer cabinet are not within the scope of the XI.E6 AMP consistent with NUREG-2191 guidance.

The 19 kV system health reports have shown white and yellow statuses for the five most recent quarters. Most issues involved scheduled end-of-life transformer replacements, transformer bushings and gasket replacements, protective relay replacements, circuit switcher replacement, breaker replacements as well as motor control center and switchgear cabinet boot replacements.

The 120VAC Vital Instrumentation Bus system health reports (5 most recent) quarters have shown white statuses due to maintenance rule function failure (FF) criterion being exceeded. The issues prompting the white condition involved failures of the Elgin Inverters and Cyberex transfer switches requiring replacements. No electrical cable connection issues were noted.

The operating experience summarized above demonstrates that PBN has very few issues involving electrical connections. This plant-specific OE review provides additional confirmation to support industry OE that shows that electrical connections have not experienced a high degree of failures from their normal design aging mechanism exposures, and that existing installation and maintenance practices at PBN are effective.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP will provide reasonable assurance that the intended functions of the metallic parts of electrical cable connections that are not subject to the environmental qualification (EQ) requirements of Title 10 of the Code of Federal Regulations (10 CFR) 50.49 and susceptible to age-related degradation resulting in increased resistance will be maintained consistent with the CLB through the SPEO.

B.2.3.44 High-Voltage Insulators

Program Description

The PBN High Voltage Insulators AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of high voltage insulators within the scope of SLR are maintained consistent with the CLB through the SPEO. The High Voltage Insulator AMP was developed specifically to age manage high voltage insulators susceptible to aging degradation due to local environmental conditions.

This AMP is a condition monitoring program that manages reduced insulation resistance of high-voltage insulators surface due to contamination from various airborne contaminates such as dust, salt, fog or industrial effluent. The metallic portions of the high-voltage insulators are subject to loss of material from either mechanical wear caused by oscillating movement of the insulators due to wind, and / or surface corrosion from substantial airborne contamination such as salt.

The program includes the inspection of the high-voltage insulators within the scope of this program to identify degradation of high-voltage insulator sub-component parts, namely; insulation and metallic elements. Visual inspection is performed to provide reasonable assurance that the applicable aging effects are identified, and high-voltage insulator age degradation is managed. Insulation materials used in high-voltage insulators may degrade more rapidly than expected when installed in an environment conducive to accelerated aging. The insulation and metallic elements of high-voltage insulators are made of porcelain, cement, malleable iron, aluminum, and galvanized steel. Significant loss of metallic material can occur due to mechanical wear caused by oscillating movement of insulators due to wind. Surface corrosion in metallic parts may appear due to airborne contamination or where galvanized or other protective coatings are worn. With substantial airborne contamination such as salt, surface corrosion in metallic parts may become significant such that the insulator no longer will support the conductor. Various airborne contaminates such as dust, salt, fog or industrial effluent can contaminate the insulator surface leading to reduced insulation resistance. Excessive surface contaminants or loss of material can lead to insulator flashover and failure.

The high-voltage insulators within the scope of this program are to be visually inspected at a frequency based on plant-specific operating experience (OE). The first inspections for SLR are to be completed prior to the SPEO.

Reduced insulation resistance can be caused by the presence of insulator surface contamination. Visual inspections may be supplemented with infrared thermography inspections to detect high-voltage insulator reduced insulation resistance.

The acceptance criteria for the high-voltage insulators are that the surfaces are free from unacceptable accumulation of foreign material, such as significant salt or dust buildup as well as other contaminants. Metallic parts are free from significant loss of materials due to pitting, fatigue, crevice, and general corrosion. Acceptance criteria will be based on temperature rise above a reference temperature for the application when thermography is used. The reference temperature will be ambient temperature, or a baseline temperature based on data from the same type of high-voltage insulator being inspected.

NUREG-2191 Consistency

The PBN High-Voltage Insulators AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E7, “High-Voltage Insulators” as modified by SLR-ISG-Electrical-2020-XX, “Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance.”

Regarding draft SLR-ISG-Electrical-2020-XX (Reference ML20156A324), PBN does not have polymer and toughened glass high-voltage insulators within the scope of SLR. Also, PBN does not have any medium-voltage insulators within the scope of SLR.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

In July 2013, the Diablo Canyon 500 kV flashover event involving high-voltage insulator(s) was reviewed. The flashover event was caused by the accumulation of contaminants (salt spray conditions by the ocean) and lack of rain for 4 weeks (rain naturally washes off accumulated salt). Also, the insulator was of the polymer type that was intended to be more resilient to accumulated contamination.

Two lessons were realized from this event; flashovers do occur from accumulated contamination in areas prone to contamination (sea spray or heavy air pollution contaminants) and polymer insulators are not immune to flashovers due to accumulated contaminants.

<u>Plant Specific Operating Experience</u>

The 345 kV System Health Report is part of the 19 kV Health Report (which also includes the 13.8 kV system). The most recent 5 quarterly health reports (19Q1-20Q1) were reviewed with statuses varying between WHITE and YELLOW during this period. The main issues preventing these health reports to post GREEN are primarily due to issues obtaining original equipment manufacturer (OEM) replacement parts for both circuit switchers and the need for a serviceable “spare” high-voltage station auxiliary transformer to be used as a contingency transformer should either inservice high-voltage station auxiliary transformer become unavailable. In summary, the aging concerns of equipment in the 345 kV system is proving challenging due to the inability to obtain OEM replacement parts which may necessitate system workarounds should the circuit switchers or high-voltage station auxiliary transformers become unavailable.

In July 2012, a trip on a 345 kV breaker occurred during a severe thunderstorm. The breaker was unable to be reset (closed), and the cause was identified as a bad or damaged polymer insulator. The original porcelain insulator was replaced with a polymer insulator in 2008, and no approved polymer replacement insulators were available. The polymer insulator was replaced with a porcelain insulator. The cause of the insulator failure was not identified but was suspected to be due to damage from the severe thunderstorm or lightning. The high-voltage insulators within the scope of the PBN AMP are porcelain station post insulators used in the SBO recovery paths. There are no polymer insulators used in PBN's SBO power paths.

During April 2013 through October 2015, the high-voltage station auxiliary transformers have experienced porcelain insulator issues ranging from chipped pieces, cracks, and previously repaired (epoxy) porcelain sections breaking loose. The causes ranged from being over 40 years old (brittleness is more sensitive to damage from inadvertent impacts) to improper (or ineffective) previous repairs. The Unit 2 high-voltage station auxiliary transformer is scheduled for refurbishment which involves replacement of auxiliary components (bushings and gaskets). The bushings and gaskets on the Unit 1 high-voltage station auxiliary transformer have already been replaced. In October 2015, potting material within the main auxiliary transformer stand-off insulators were degrading. The insulators were replaced with salvaged / refurbished spare low-voltage station auxiliary transformer parts.

High-voltage insulators associated with active components (e.g. transformer bushings) are piece parts of those components and are inspected and maintained along with the active component. These components are not within the scope of this AMP.

In October 2015, there were multiple cases of iso-phase bus insulators found damaged (cracked, broken) requiring replacement. Note that PBN's iso-phase bus does not perform or support a SLR intended function.

In October 2015, an apparent tracking mark was discovered on an insulator in the 19 kV iso-phase bus. The "tracking" mark was found to be a very localized area of contamination requiring cleaning and restoration of operation.

System / program health reports are available on the NextEra corporate portal under "ER dashboard." Plant-specific OE indicates that aged high-voltage porcelain insulators require periodic visual inspections and periodic coating or cleaning as preventive measures to mitigate flashover events.

For all three NRC 71003 Reviews; Level 1, License Renewal Aging Management Program Effectiveness Review, Phase 2 Point Beach Nuclear Plant, Unit 1 NRC Post-Approval Site Inspection Report for License Renewal, and Phase 2 Point Beach Nuclear Plant, Unit 2 NRC Post-Approval Site Inspection Report for License Renewal, there were no issues raised that were specific to high-voltage switchyard insulators.

The operating experience summarized shows PBN has had isolated instances involving medium-voltage (19 kV iso-phase bus) and high-voltage 345 kV (auxiliary transformers) insulators. Although none of this equipment is within the scope of this PBN AMP, the new PBN AMP will be effective because it incorporates proven condition monitoring inspections and high-voltage insulator coating and cleaning activities to manage high-voltage insulator aging effects.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PBN High-Voltage Insulators AMP will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PBN High-Voltage Insulators AMP will provide reasonable assurance that the intended functions of the high-voltage insulators susceptible to age-related degradation resulting in decreased insulation resistance of the porcelain insulators and loss of material of the metallic components will be maintained consistent with the CLB through the SPEO.

APPENDIX C

LICENSEE SPECIFIC ACTIVITIES RELATIVE TO REACTOR VESSEL INTERNALS

POINT BEACH NUCLEAR PLANT UNITS 1 AND 2

SUBSEQUENT LICENSE RENEWAL APPLICATION

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C.1.0 Purpose

The existing PBN Reactor Vessel Internals AMP is based on Electric Power Research Institute (EPRI) Technical Report No. 1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)," and is implemented in accordance with Nuclear Energy Institute (NEI) 03-08, "Guideline for the Management of Materials Issues". The staff approved the industry augmented inspection and evaluation (I&E) criteria for pressurized water reactor (PWR) reactor vessel internals (RVI) components in NRC Safety Evaluation (SE), Revision 1, dated December 16, 2011 and the staff subsequently approved the PBN license renewal reactor vessel internals program report (Reference ML15079A087), which is based on the guidance of MRP-227-A.

Because the guidelines of MRP-227-A are based on an analysis of the reactor vessel internals that considers the operating conditions up to a 60 year operating period, NUREG-2191 requires these guidelines to be supplemented through a gap analysis that identifies enhancements to the program that are needed to address an 80-year operating period.

The PBN subsequent license renewal (SLR) RVI gap analysis uses the most recent guidelines provided in EPRI Technical Report No. 3002017168, MRP-227 Rev. 1-A (Reference C.9.1) as the baseline to address an 80-year operating period, consistent with the NRC SE dated April 15, 2019 (Reference ML19081A001) indicating that MRP-227 Rev. 1 can be used as a starting point for performing a gap analysis in order to develop an RVI AMP for the 60-80-year subsequent period of extended operation (SPEO), and the NRC SE dated February 19, 2020 (Reference ML20006D152) indicating that MRP-227 Rev. 1-A is acceptable to the extent delineated in the April 15 2019 SE. Revision 1 of the guidelines provides updates based on Revision 1 of the NRC SE for MRP-227 Revision 0 (Reference ML11308A770) and includes operating experience and new knowledge gained from materials testing, modeling, and research. MRP-227 Rev. 1-A is the acceptance version incorporating changes from the NRC SE approving MRP-227 Revision 1. Note that MRP-227 Rev. 1-A still only addresses an operating period of 60 years and will be implemented at PBN for the current period of extended operation by January 1, 2022.

To address the SPEO, the guidelines in MRP-227 Rev. 1-A are supplemented with the industry efforts up to this point to address the 80-year operating period. The current industry body of work to support aging management of the reactor vessel internals for 80-years of operation is listed below;

- EPRI Technical Report No. 3002010268, MRP-175, Revision 1, Materials Reliability Program: PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values (Reference C.9.2)

- EPRI Technical Report No. 3002013220, MRP-191, Revision 2, EPRI Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Design (Reference C.9.3)

- MRP 2018-022, Interim Guidance for the Pressurized Water Reactor Internals Inspection and Evaluation Guidelines, MRP-227-A, for Subsequent License Renewal – Westinghouse and Combustion Engineering-Designed Reactor Vessel Internals (Reference ML19081A057)

EPRI recommendations in MRP 2018-022 were drafted prior to the publication of MRP-227 Rev. 1-A, and as such references MRP-227-A and MRP-227 Rev. 1. However, the recommendations in MRP 2018-022 implement the screening and threshold values of MRP-175 Rev. 1, and the screening categorization and ranking of MRP-191 Rev. 2. To capture any changes which occurred during the SE process and inform the PBN implementation of the guidance, this gap analysis compares the MRP 2018-022 recommended table entries against both MRP-227-A and MRP-227 Rev. 1-A.

To appropriately implement MRP-227 Rev. 1-A, there are five comments from the NRC staff on the final publication of MRP-227 Rev. 1-A which should be addressed. Per MRP 2020-012 (Reference ML20127H664) Table 2, items 5a, 5b, 5d, and 5e are the only comments applicable to Westinghouse designs. These all represent administrative changes in the component notes of Table 4-3 and 4-6 of MRP-227 Rev. 1-A resulting from removing unused notes and adding clarifying information addressed in responses to requests for additional information. These comment dispositions do not include any changes needed to implement the guidance.

C.2.0 Analysis of MRP-227 Rev. 1-A Development

MRP-227 Rev. 1-A consists of inspection and evaluation (I&E) guidelines for managing long-term aging of pressurized water reactor (PWR) internals. These guidelines are based on a broad set of assumptions which encompass the range of current unit conditions for the U.S. fleet of PWRs, including specific analysis of Westinghouse-designed reactor vessel internals. The process used to develop the MRP-227 recommendations was identified in the MRP-227 Roadmap (Reference ML12017A199) submitted to the NRC along with the initial submittal of MRP-227. This roadmap is summarized by eight steps listed below. These eight steps are reflected in the form of a flowchart in MRP-227 Rev. 1-A Figure 2-2. Each of these 8 steps are evaluated for potential impact of the 80-year operating period. By following the steps used to develop guidance for managing reactor vessel internals for 60 years, and applying the inputs identified in Section C.1.0 relevant for 80-years, the resulting changes will be appropriate to supplement the current guidance and provide aging management of the reactor vessel internals for an 80-year operating period.

1. Identify internals components, materials, and environments
2. Identify degradation screening criteria
3. Characterize components and screen for degradation
4. Failure modes, effects, and criticality assessment (FMECA) review
5. Severity categorization
6. Engineering evaluation and assessment
7. Categorize for inspection (Primary, Expansion, Existing, No Additional Measures) and aging management strategy
8. Preparation of MRP-227 Rev. 1-A inspection and evaluation guidelines

Sections C.3.0 through C.5.0 provide the relevant 80-year inputs for each of these steps and demonstrate their applicability to PBN.

C.3.0 Step 1

Identify internals components, materials, and environments

A complete listing of the components evaluated by MRP-227 Rev. 1-A is prepared in MRP-191, Revision 2, Table 4-4. A review of all these components for applicability to PBN was provided by Westinghouse through LTR-AMLR-20-26-NP (Reference C.9.4). This listing demonstrates the guidance documents are applicable to PBN as every component type and material combination is recognized by the guidance, with one exception. The upper core plate insert locking devices material listed in MRP-191 Revision 2 is Type 304 SS and Type 316 SS. The PBN Unit 1 upper core plate insert locking devices material is Type 304L SS. This difference is negligible as both materials are austenitic stainless steel and there are no differences in the degradation mechanism screening criteria between the PBN component material and those listed in MRP-191 Revision 2. A complete list of the components and their respective materials is provided in Table C.3-1 below.

Table C.3-1 PBN Units 1 & 2 Reactor Vessel Internals Sub-assembly Components, Materials, and Intended Functions

Assembly	Subassembly	Component	Material Type/ Grade
Upper internals assembly	Control rod guide tube assemblies and downcomers	Bolts	316 SS
		C-tubes	304 SS
		Guide tube enclosures	304 SS
		Flanges - intermediate	304 SS
			CF8
		Flanges - lower	304 SS
			CF8
		Flexureless inserts	304 SS
		Flexureless inserts (spring)	Alloy 718
		Guide plates (cards)	304 SS
			CF8
		Guide tube support pins	316 SS
		Housing plates	304 SS
			CF8
		Sheaths	304 SS
		Support pin nuts	316 SS
	Mixing devices	Mixing devices	CF8
			304 SS
	Upper core plate and fuel alignment pins	Fuel alignment pins	304 SS
		Upper core plate	304 SS
		Upper core plate insert	304 SS
			Stellite
		Upper core plate insert bolts	316 SS

Assembly	Subassembly	Component	Material Type/ Grade
Upper internals assembly (cont.)		Upper core plate insert locking devices and dowel pins	304 SS (Note 1)
	Upper instrumentation conduit and supports	Bolting	316 SS
			304 SS
		Brackets, clamps, terminal blocks, and conduit straps	304 SS
			CF8
		Conduit seal assembly: body, tubesheets, tubesheet welds	304 SS
		Conduit seal assembly: tubes	304 SS
		Conduits	304 SS
		Flange base	304 SS
		Locking caps	304L SS
		Support tubes	304 SS (U1)
			304L SS (U2)
	Upper support column assemblies	Adapters	304 SS
		Bolts	316 SS
		Column bases	CF8
		Column bodies	304 SS
		Extension tubes	304 SS
		Flanges	304 SS
		Nuts	304 SS
	Upper support plate assembly – flat plate design	Upper support plate	304 SS
		Deep beam ribs	304 SS
		Deep beam stiffeners	304 SS
		Bolts	316 SS
Lower internals assembly	Baffle and former assembly	Baffle-edge bolts	316 SS
		Baffle plates	304 SS
		Baffle-former bolts	347 SS
		Barrel-former bolts	347 SS
		Former dowel pins	304 SS
		Former plates	304 SS
	Bottom- mounted instrumentation (BMI) column assemblies	BMI column bodies	304 SS
		BMI column bolts	316 SS
		BMI column cruciforms	CF8
			304 SS
		BMI column extension bars	304 SS
		BMI column extension tubes	304 SS
		BMI column locking devices	304L SS
		BMI column nuts	304 SS
	Core barrel	Core barrel flange	304 SS
		Upflow conversion core barrel plug body	304 SS
		Upflow conversion core barrel plug mandrel	316 SS
		Core barrel outlet nozzles	304 SS

Assembly	Subassembly	Component	Material Type/ Grade
	Core barrel (cont.)	Upper core barrel (includes UAW)	304 SS
		Upper core barrel (includes UFW and UGW)	304 SS
		Lower core barrel (includes MAW and LAW)	304 SS
		Lower core barrel (includes LGW and LFW)	304 SS
		Safety injection nozzle interface	304 SS
	Diffuser plate	Diffuser plate	304 SS
	Flux thimble (tubes)	Flux thimble tube plugs	304 SS
		Flux thimbles (tubes)	316 SS
	Head cooling spray nozzles	Head cooling spray nozzles	304 SS
	Irradiation specimen guides	Irradiation specimen access plug (dowel pin)	316 SS
		Irradiation specimen access plug (plug)	304 SS
		Irradiation specimen access plug (spring)	X-750
		Irradiation specimen guide	304 SS
	Lower core plate and fuel alignment pins	Fuel alignment pins	304 SS
		LCP and manway bolts	316 SS
		Lower core plate	304 SS
	Lower support column assemblies	Lower support column bodies	304 SS
		Lower support column bolts	316 SS
		Lower support column nuts	304 SS
		Lower support column bolt locking devices (Note 2)	304L SS
		Lower support column bolt locking devices (Note 2)	304 SS
		Lower support column sleeves	304 SS
	Lower support forging	Lower support forging	304 SS
	Thermal shield	Thermal shield bolts	316 SS
		Thermal shield dowels	316 SS
			304 SS
		Thermal shield flexures	304 SS
		Thermal shield flexure bolts	316 SS
		Thermal shield flexure locking devices and dowel pins	304L SS
		Thermal shield	304 SS
	Radial support keys	Radial support key bolts	316 SS
		Radial support keys	304 SS
		Radial support keys	Stellite
	Secondary core support (SCS) Assembly	SCS base plate	304 SS
		SCS energy absorber	304 SS
		SCS guide post	304 SS (U1)
			CF8 (U2)

Assembly	Subassembly	Component	Material Type/ Grade
Lower internals assembly (cont.)	Secondary core support (SCS) Assembly (cont.)	SCS housing	304 SS (U1)
		SCS housing Upper and lower tie plates	CF8 (U2) 304 SS
		Clevis insert bolts	X-750
Alignment and interfacing components	Alignment and interfacing component	Clevis insert dowels	Alloy 600
		Clevis insert locking devices	Alloy 600
		Clevis inserts	Alloy 600
		Clevis inserts	Stellite
		Head and vessel alignment pin bolts	316 SS
		Head and vessel alignment pins	304 SS
		Internals hold-down spring	403 SS
		Upper core plate alignment pins	304 SS
		Upper core plate alignment pins Thermal sleeves	Stellite 304 SS
		Thermal sleeve guide funnels	CF8

Notes

1. Upper core plate insert locking devices at Unit 1 are 304L SS.
2. The lower support column bolt locking device is listed as 304 SS within Table 4-6, Table 5-1, Table 6-10, and Table 7-2 of MRP-191, Revision 2 and also as 304L SS in Table 4-4 of MRP-191, Revision 2. Both materials are listed in this table, however, only 304L is applicable to PBN Units 1 and 2.

C.4.0 Steps 2 Through 5

2) Identify degradation screening criteria

Identification of degradation screening criteria is accomplished through MRP-175, Revision 1. This report developed screening and threshold values under the assumption of 80-years of operation. As such, the screening threshold values are applicable for the subsequent license renewal period.

3) Characterize and screen components, 4) FMECA review, and 5) Severity categorization

These three steps are accomplished through MRP-191 Revision 2 which performs these analyses under the assumption of 80-years of operation. As such, the results are applicable for the subsequent license renewal period and provide the screening, FMECA, and severity categorization for this gap analysis. Table C.3-1 demonstrates the component material assumptions of MRP-191, Revision 2, are consistent with the material types at PBN and as such, the screening, FMECA review, and severity categorization results are applicable.

C.5.0 Steps 6 and 7

6) Engineering evaluations and assessments and 7) Categorize for inspection

The engineering evaluations and assessments and categorization for inspection performed in MRP-227 Rev. 1-A are only applicable for 60 years of operation. As such, the inspection categories require evaluation for applicability to 80-years of operation.

To facilitate this evaluation, EPRI MRP 2018-022 is applied to the baseline inspection categories established in MRP-227 Rev. 1-A. The baseline inspection categories are altered based on the screening, FMECA, and severity categorization of MRP-191, Revision 2, to inform the evaluation.

MRP 2018-022 used several assumptions for the operation of the power plant. These assumptions have been validated for PBN Units 1 and 2 in the NRC SE of the initial license renewal inspection program and continue to be applicable for SLR.

(a) Each of the units has operated for 30 years or less with high-leakage core loading patterns (fresh fuel assemblies loaded in peripheral locations) followed by implementation of a low-leakage fuel management strategy for the remaining years of operation - the limitations defining low-leakage operation for SLR considerations are the same as those used for the first period of extended operation (PEO):

- Heat generation rate figure of merit: $F \leq 68$ Watts/cm^3
- Average core power density < 124 Watts/cm^3
- Active fuel to fuel alignment plate distance > 12.2 inches

(b) The units have operated for the majority of their lifetimes as base-loaded units and are currently operating as base-loaded power plants (each unit operates at fixed thermal power levels and does not usually vary power on a calendar or load demand schedule).

(c) The units have not implemented design changes beyond those identified in general industry guidance or recommended by the original vendors.

(d) The unit listings of functional components have been confirmed to include the components and material class as listed in the latest revision of MRP-191.

MRP 2018-022 addresses increases in neutron irradiation dose at 80-years through calculations specifically for representative Westinghouse-designed plants. To obtain representative dose projections with a reasonable amount of added conservatism, dose projections were generated using a model for a representative 3-loop plant at 72 EFPY. To account for variations in axial and radial power shapes, two different dose projections were generated:

- A flat axial power shape that produced conservative dose projection results above and below the active fuel, and

- A best-estimate and realistic axial power shape that produced dose projection results that were more limiting in the radial direction.

These two dose projections were overlaid and the higher dose at any point was utilized. By confirming assumptions (a) through (d) above, the dose projection used is demonstrated to be applicable to PBN. For additional assurance, the representative model is confirmed to be bounding to the site specific conditions at PBN through Westinghouse letter report LTR-REA-20-29-NP (Reference C.9.5). The PBN specific fluence model to demonstrate it is bounded by the industry representative fluence model is performed to the standards in WCAP-18124-NP-A (Reference ML18204A010) which has been determined by the NRC to be an applicable methodology for projecting RVI fluence.

MRP 2018-022 evaluates the components which increase in severity categorization as compared to MRP-227-A to identify components which may require a new inspection category. While MRP-227 Rev. 1-A was not available at the time, MRP-227 Rev. 1 and MRP-227-A were used to make comparisons. Based on these evaluations, MRP 2018-022 provided current and revised table entries, comparing the MRP-227-A inspection tables to the recommended new entries. The tables presented below include the MRP-227 Rev. 1-A entries as well to facilitate incorporating the most recent guidance in addition to the changes necessary to manage the reactor vessel internals for 80-years. Each set of tables is followed by a summary of the changes for each component and how they will be implemented at PBN.

MRP-227-A Entries for Westinghouse Primary Components

Primary Item	Applicability	Effect (Mechanism)	Expansion Link	Examination Method / Frequency	Examination Coverage
Baffle-Former Assembly Baffle-edge bolts	All plants with baffle-edge bolts	Cracking (IASCC, Fatigue) that results in • Lost or broken locking devices • Failed or missing bolts • Protrusion of bolt heads	None	Visual (VT-3) examination, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval	Bolts and locking devices on high fluence seams. 100% of components accessible from core side.
Baffle-Former Assembly Baffle-former bolts	All plants	Cracking (IASCC, Fatigue)	Lower support column bolts, Barrel-former bolts	Baseline volumetric (UT) examination between 25 and 35 EFPY, with subsequent examination after 10 to 15 additional EFPY to confirm stability of bolting pattern. Re-examination for high leakage core designs requires continuing examinations on a ten-year interval	100% of accessible bolts or as supported by plant-specific justification. Heads accessible from the core side, UT accessibility may be affected by complexity of head and locking device design.

MRP-227 Rev. 1-A Entries for Westinghouse Primary Components

Primary Item	Applicability	Effect (Mechanism)	Expansion Link (Note 1)	Examination Method / Frequency	Examination Coverage
Baffle-Former Assembly Baffle-edge bolts	All plants with baffle-edge bolts	Cracking (IASCC, Fatigue) that results in • Lost or broken locking devices • Failed or missing bolts • Protrusion of bolt heads Aging Management (IE and ISR) (Note 4)	None	Visual (VT-3) examination, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval	Bolts and locking devices on high fluence seams. 100% of components accessible from core side.
Baffle-Former Assembly Baffle-former bolts	All plants (See WEC NSAL-16-1)	Cracking (IASCC, Fatigue) Aging Management (IE and ISR) (Note 4)	Lower support column bolts, Barrel-former bolts	Baseline volumetric (UT) examination interval is dependent on the plant design (Note 8). Subsequent examination is dependent on the plant design and the results of the baseline inspection (Note 9)	100% of accessible bolts. (Note 3)

Notes

1. Examination acceptance criteria and expansion criteria for the Westinghouse components are in Table 5-3 of MRP-227 Rev. 1-A.
3. A minimum of 75% of the total bolt population (examined + unexamined), including coverage consistent with the Expansion criteria in Table 5-3 of MRP-227 Rev. 1-A., must be examined for inspection credit.
4. Void swelling effects on this component are managed through management of void swelling on the entire baffle-former assembly.
8. In accordance with MRP 2017-009 and MRP 2017-010, Tier 1 plants are to perform the baseline UT examination by 20 EFPY or during the next refueling outage after March 1, 2016. Per MRP 2017-009, Tier 2 plants are to perform the baseline UT examination at no later than 30 EFPY (initial Tier 2 plant baseline UT exams performed prior to 1/1/2018 are acceptable). All other remaining plants are to perform the baseline UT examination at no later than 35 EFPY.
9. Re-examination periods shall be determined by plant-specific evaluation per the MRP-227 Needed Requirement 7.5 as documented and dispositioned in the owner's plant corrective action program. If atypical or aggressive baffle-former bolt degradation as defined in MRP 2017-009 (i.e., ≥3% of baffle-former bolts with UT or visual indications or clustering* for downflow plants and ≥5% of baffle-former bolts with UT or visual indications or clustering* for upflow plants) is observed, the interim guidance (MRP 2016-021 and MRP 2017-009) provides limitations to the permitted reinspection interval (not to exceed 6 years maximum) unless further evaluation is performed to justify a longer interval (See Applicant/Licensee Action Item 1 in the NRC SE for evaluation submittal requirements). If evaluation justifies a longer reinspection interval, it is not permitted to exceed 10 years.

*"Clustering" is defined per NSAL-16-1 Rev. 1 as three or more adjacent defective baffle-former bolts or more than 40% defective baffle-former bolts on the same baffle plate. Untestable bolts should be reviewed on a plant-specific basis consistent with WCAP-17096-NP-A for determination if these should be considered when evaluating clustering.

MRP 2018-022 Recommended Entries for Westinghouse Primary Components

Primary Item	Applicability	Effect (Mechanism)	Expansion Link (Note 1)	Examination Method / Frequency	Examination Coverage
Baffle-Former Assembly Baffle-edge bolts Bracket bolts[1]	All plants with baffle-edge bolts or bracket bolts	Cracking (IASCC, Fatigue) that results in • Lost or broken locking devices • Failed or missing bolts • Protrusion of bolt heads Aging Management (IE and ISR)	None	Visual (VT-3) examination, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval	Bolts and locking devices on high fluence seams. 100% of components accessible from core side.
Baffle-Former Assembly Baffle-former bolts Corner bolts[2]	All plants (corner bolts are only applicable to some plants)	Cracking (IASCC, Fatigue) Aging Management (IE and ISR)	Lower support column bolts, Barrel-former bolts	Examination according to the requirements of MRP 2017-009 [10]	100% of accessible bolts.

Notes

1. Bracket bolts are only applicable to 4-loop plants originally designed for downflow configuration.
2. Corner bolts are only applicable to the 3-loop design plants which include corner angle baffle plates.

Baffle-edge bolts

The additional recommendations in MRP 2018-022 is to include the bracket bolts.

PBN Actions

Bracket bolts are not an applicable component for PBN, and as such, the MRP-227 Rev. 1-A table entry will be used for baffle-edge bolts.

Baffle-former bolts

MRP 2018-022 incorporates by reference the requirements of MRP 2017-009 (Reference ML17310A861) and adds corner bolts. The MRP-227 Rev. 1-A directly incorporates the examination method / frequency requirements with expanded context as well as establishing a minimum criteria for accessible bolts.

PBN Actions

Corner bolts are not an applicable component for PBN and will not be incorporated. As the differences in the two tables recommendations for baffle-former bolts is a byproduct of publication timing amid an evolving industry issue rather than a difference due to the SLR expert panel review, the MRP-227 Rev. 1-A table entry will be used for baffle-former bolts.

MRP 2018-022 Expected New Entries for Westinghouse Primary Components

Primary Item	Applicability	Effect (Mechanism)	Expansion Link (Note 1)	Examination Method / Frequency	Examination Coverage
Alignment and Interfacing Components Clevis insert bolts Clevis insert dowels	All plants	Cracking (SCC), Loss of material (Wear)	None	Visual (VT-3) examination no later than 2 refueling outages from the beginning of the first license renewal period. Subsequent examinations on a ten-year interval	All clevis insert bolts and clevis insert dowels
Alignment and Interfacing Components Thermal sleeves	All plants with thermal sleeves	Loss of material (Wear)	None	Volumetric (UT) examination according to the requirements and initial inspection timing of TB-07-02 and WCAP-16911-P Measurement of thermal sleeve guide funnels height according to the requirements and timing of TB-07-02 and PWROG-16003-P Subsequent examinations based on calculated wear projections	Thermal sleeve wear surfaces according to the requirements of TB-07-02, WCAP-16911-P, and PWROG-16003-P
Radial Support Keys Radial support keys	All plants	Loss of material (Wear)	None	Visual (VT-3) examination no later than 2 refueling outages from the beginning of the first license renewal period. Subsequent examinations on a ten-year interval.	Wear surfaces on all radial keys
Alignment and Interfacing Components Clevis bearing Stellite wear surface	All plants	Loss of material (Wear)	None	Visual (VT-3) examination no later than 2 refueling outages from the beginning of the first license renewal period. Subsequent examinations on a ten-year interval.	Wear surfaces on all clevis inserts

Clevis inserts

For the new primary entries, the MRP 2018-022 guidance escalates the clevis insert bolts from Existing Components to Primary Components. The examination method and frequency is consistent with the previously required method and frequency under the ASME Section XI inspection criteria. MRP-227 Rev. 1-A maintains this component as Existing Programs but provides a clarifying note on the examination method. Additionally, MRP 2018-022 includes the clevis insert dowels with the clevis insert bolts.

MRP 2018-022 adds the clevis bearing Stellite wear surface to the list of Primary Components. MRP-227 Rev. 1-A adds this as a new component, but to the Existing Programs list of components, in the same item line as the clevis insert bolts, and as such has the same clarifying note.

PBN Actions

PBN will align with the new inspection categories for the clevis insert bolt, clevis insert dowels and clevis bearing Stellite wear surface as shown in MRP 2018-022. This is still a developing industry issue and PBN will manage it as a Primary component in the SPEO unless it changes to an Existing component based on the latest NRC-approved version of MRP-227 that addresses 80 years of operation. The notes added to the examination method are considered relevant operating experience clarifications that are appropriate to include as a part of aligning with MRP-227 Rev. 1-A.

Radial Support Keys

The addition of the radial support keys in the Primary Components inspection category is unique to MRP 2018-022 and has not previously appeared in NRC approved guidance.

PBN Actions

This entry is an appropriate difference due to the expert review panels consideration for operation for 80-years and will be incorporated by PBN.

Thermal Sleeves

The addition of the CRDM thermal sleeves in the Primary Components inspection category is unique to MRP 2018-022. However, during the NRC review of MRP-227 Rev. 1, the staff asked the industry to describe how the recent CRDM thermal sleeve wear operating experience will be addressed in MRP-227 Rev. 1. The industry response cited that the development of interim guidance to manage these components was still ongoing and would not be complete before the scheduled completion of the MRP-227 Rev. 1 SER.

PBN Actions

The addition of the CRDM thermal sleeves to the Primary Components inspection category is not appropriate for PBN. MRP 2018-022 cites the inclusion of these components to be based on the presence of the loss of material due to wear degradation mechanism in multiple plants and the potential to cause a possible safety hazard. The most recent industry guidance addressing CRDM thermal sleeves is NSAL-18-1 (Reference ML18198A275) which clarifies that the PBN site specific design will limit wear and preclude flange separation. Based on these design characteristics NSAL-18-1 states that the inspection recommendations do not apply to the PBN CRDM thermal sleeve. Additionally, as a T-hot plant, the only recommended actions applicable to PBN are to continue to monitor the industry OE for this issue.

PBN will manage the CRDM thermal sleeves as a No Additional Measures components. Note that per Element 10 of the PBN SLR Reactor Vessel Internals AMP, PBN is committed to following industry operating experience and will follow all relevant industry guidance. Additionally, PBN is committed to implementing any future NRC approved revisions of MRP-227. As such, the CRDM thermal sleeves will continue to be managed appropriately as guidance is informed by further operating experience, in particular, the ongoing industry baseline inspections.

MRP 2018-022 Expected New Entries for Westinghouse Existing Components					
Item	**Applicability**	**Effect (Mechanism)**	**Reference**	**Examination Method**	**Examination Coverage**
UCP and Fuel Alignment Pins Fuel alignment pins	All plants with malcomized fuel alignment pins on the UCP	Loss of material (Wear)	ASME Code	Visual (VT-3) examination	All accessible surfaces at specified frequency
LCP and Fuel Alignment Pins Fuel alignment pins	All plants with malcomized fuel alignment pins on the LCP	Loss of material (Wear)	ASME Code	Visual (VT-3) examination	All accessible surfaces at specified frequency

Fuel Alignment Pins

In 2016, Westinghouse released technical bulletin TB-16-4, “Fuel Alignment Pin Malcomized Surface Degradation”, which identified PBN as being potentially susceptible to surface degradation of the fuel alignment pins in both the upper core plate and lower core plate. The addition of the upper and lower core plate fuel alignment pins in the Existing Components inspection category is unique to MRP 2018-022 and has not previously appeared in NRC approved guidance. This inclusion is based on operating experience documented in TB-16-4.

PBN Actions

TB-16-4 documents that both the upper and lower core plate fuel alignment pins have a malcomized surface at PBN. As such, these components will be incorporated into the Existing Programs inspection category at PBN.

C.6.0 Step 8

8) Preparation of inspection and evaluation guidelines

The inspection and evaluation guidelines created for MRP-227 Rev. 1-A will remain applicable, as modified by the changes summarized in Section C.7.0. The implementation of these modified guidelines at PBN for the subsequent period of extended operation is shown in Attachments 1 through 3 of this Appendix.

C.7.0 Operating Experience

PBN is committed to tracking industry operating experience and implementing all relevant interim guidance as demonstrated in Element 10 of the SLR RVI AMP (Section B.2.3.7). Due to the recent publishing of MRP-227 Rev. 1-A which serves as an update to the guidelines to incorporate operating experience, there are no examples of industry operating experience which need to be addressed by this gap analysis.

While this gap analysis adds the CRDM thermal sleeves to the No Additional Measures inspection category, based on the current guidance in NSAL-18-1 identifying PBN as a plant with 14x14 guide tubes with gaps between the guide funnel and upper guide tube that will limit flange wear and prevent flange separation, PBN will continue to track the latest operating experience and implement the most recent applicable guidelines for inspecting the CRDM thermal sleeves.

C.8.0 Conclusions

Four components are added to the Primary Components inspection category in addition to those identified in MRP-227 Rev. 1-A. Two of these components are new additions to the aging management program, clevis insert dowels and radial support keys. The clevis insert bolts are escalated from Existing Programs inspection category to the Primary Components inspection category. The clevis bearing Stellite wear surface is a new addition to the MRP-227 Rev. 1-A Existing Programs inspection category and is escalated to the Primary Components inspection category consistent with the guidance in MRP 2018-022.

Two components are added to the Existing Programs inspection category. The upper and lower core plate fuel alignment pins are added per the MRP 2018-022 guidance. The CRDM thermal sleeves are recommended to be added to the Primary Components inspection category per MRP 2018-022. However, the industry operating experience cited for the severity category ranking is not applicable to PBN. As such, the CRDM thermal sleeves remain in the No Additional Measures inspection category. Attachments 1 through 3 show the PBN SLR Primary, Expansion, and Existing Program inspection categories, taken respectively from tables 4-3, 4-6, and 4-9 of MRP-227 Rev. 1-A and modified by this gap analysis.

C.9.0 References

C.9.1. EPRI Technical Report No. 3002017168, Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227 Revision 1-A), ADAMs Accession No. ML19339G350.

C.9.2. EPRI Technical Report No. 3002010268, Materials Reliability Program: PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values, Revision 1 (MRP-175), October 2017, ADAMs Accession No. ML17361A168.

C.9.3. EPRI Technical Report No. 3002013220, Revision 2, EPRI Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Design (MRP-191), November 2018, ADAMs Accession No. ML19081A057.

C.9.4. Westinghouse LTR-AMLR-20-26-NP, Revision 1, "Transmittal of Results from the MRP-191 Revision 2 Review in Support of Subsequent License Renewal for Point Beach Units 1 and 2," June 11, 2020 (Enclosure 4, Attachment 20).

C.9.5. Westinghouse LTR-REA-20-29-P/NP, Revision 0, "Comparison of Point Beach Unit 1 Reactor Internals Fluence Values to the Representative 3-Loop Plant for MRP-191, Revision 2," July 7, 2020 (Enclosure 4, Attachment 21 and Enclosure 5, Attachment 14).

Table C.A1 – Primary Components

Item	Effect (Mechanism)	Expansion Link (Note 1)	Examination Method/Frequency	Examination Coverage	Source of Revision / Addition
W1.Control Rod Guide Tube Assembly Guide plates (cards)	Loss of material (Wear)	None	Per the requirements of WCAP-17451-P, including subsequent examinations (Note 5).	Examination coverage per the requirements of WCAP-17451-P, Revision 1 (Note 5).	MRP-227, Rev. 1-A added WCAP-17451-P as supplemented by MRP-2018-007 to the examination coverage, method, and frequency.
W2.Control Rod Guide Tube Assembly Lower flange welds	Cracking (SCC, Fatigue) Aging Management (IE and TE)	W2.1.Remaining accessible CRGT assembly lower flange welds W2.2.BMI column bodies	Enhanced Visual (EVT-1) examination to determine the presence of crack-like surface flaws in flange welds no later than 2 refueling outages from the beginning of the license renewal period and subsequent examination on a ten-year interval	100% of outer (accessible) CRGT lower flange weld surfaces and 0.25-inch of the adjacent base metal on the individual periphery CRGT assemblies. (Note 2)	Rev. 1-A added Expansion to the remaining CRGT lower flange welds, removed Expansion to upper core plate and lower support forging, specified 0.25 inch of base metal to examination coverage.
W3.Core Barrel Assembly Upper flange weld (UFW)	Cracking (SCC)	W3.1.Upper girth weld (UGW), W3.3.lower flange weld (LFW), W3.2.upper axial welds (UAW), and W3.4.lower support forging	Enhanced visual (EVT-1) examination, no later than 2 refueling outages from the beginning of the license renewal period and subsequent examination on a ten-year interval.	100% of the accessible weld length of one side of the UFW and 3/4" of adjacent base metal shall be examined. (Note 6)	Rev. 1-A removed Expansion to the core barrel outlet nozzles and lower support column bodies, added Expansion to UGW, LFW, and UAW.
W4.Core Barrel Assembly Lower girth weld (LGW)	Cracking (SCC, IASCC, Fatigue) Aging Management (IE)	W4.1.Upper core plate W4.2lower support column bodies W4.2.Middle Axial Weld (MAW) W4.3.Lower Axial Weld (LAW)	Enhanced visual (EVT-1) examination, no later than 2 refueling outages from the beginning of the license renewal period and subsequent examination on a ten-year interval.	100% of the accessible weld length of the OD of the LGW and 3/4" of adjacent base metal shall be examined. (Note 6)	Rev. 1-A added Expansion to the upper core plate, lower support column bodies, and MAW. Added 3/4" of adjacent base metal to the examination coverage and specified the inspection will be performed on the OD.
W5.Baffle-Former Assembly Baffle-edge bolts	Cracking (IASCC, Fatigue) that results in • Lost or broken locking devices • Failed or missing bolts • Protrusion of bolt heads Aging Management (IE and ISR) (Note 4)	None	Visual (VT-3) examination, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval.	Bolts and locking devices on high fluence seams. 100% of components accessible from core side.	No changes.

Table C.A1 – Primary Components

Item	Effect (Mechanism)	Expansion Link (Note 1)	Examination Method/Frequency	Examination Coverage	Source of Revision / Addition
W6.Baffle-Former Assembly Baffle-former bolts (Note 7)	Cracking (IASCC, Fatigue) Aging Management (IE and ISR) (Note 4)	W6.2.Lower support column bolts, W6.1.Barrel-former bolts	Baseline volumetric (UT) examination between 25 and 35 EFPY, with subsequent examinations on a ten-year interval. (Notes 8 and 9)	100% of accessible bolts (Note 3).	Rev. 1-A reduced the examination coverage to only 100% of accessible bolts.
W7.Baffle-Former Assembly Assembly (Includes: Baffle plates, baffle edge bolts and indirect effects of void swelling in former plates).	Distortion (Void Swelling), or Cracking (IASCC) that results in: • Abnormal interaction with fuel assemblies • Gaps between plates • Broken or damaged edge bolts	None	Visual (VT-3) examination to check for evidence of distortion, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval.	Core side surface: • High fluence baffle joints • Top and bottom edge of baffle plates • Bolts and locking devices	Rev. 1-A clarifies the extent of examination coverage.
W8.Aligning and Interfacing Components Internals hold down spring (304 SS)	Distortion (Loss of Load)	None	N/A	N/A	This line item is not applicable to PBN due to a difference in material. PBN has a 403 SS hold down spring which is a No Additional Measures component.
W9.Thermal Shield Assembly Thermal shield flexures	Cracking (Fatigue) or Loss of Material (Wear) that results in thermal shield flexures excessive wear, fracture, or complete separation	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the license renewal period. Subsequent examinations on a ten-year interval.	100% of accessible surfaces of 100% of thermal shield flexures. (Note 8)	Rev. 1-A clarified the examination coverage is limited to accessible surfaces.
W10.Alignment and Interfacing Components Clevis insert bolts Clevis insert dowels (Note 11)	Cracking (SCC), Loss of material (Wear)	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the subsequent license renewal period. Subsequent examinations on a ten-year interval.	All accessible clevis insert bolts and clevis insert dowels	MRP 2018-022 added the clevis insert bolts and dowels to the Primary category.
W11.Radial Support Keys Radial support keys	Loss of material (Wear)	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the subsequent license renewal period. Subsequent examinations on a ten-year interval.	Wear surfaces and radial support keys	MRP 2018-022 added the radial support keys to the Primary category.

Table C.A1 – Primary Components

Item	Effect (Mechanism)	Expansion Link (Note 1)	Examination Method/Frequency	Examination Coverage	Source of Revision / Addition
W14.Alignment and Interfacing Components Clevis bearing Stellite wear surfaces	Loss of material (Wear)	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the subsequent license renewal period. Subsequent examinations on a ten-year interval.	Wear surfaces and radial support keys	Rev. 1-A added the clevis bearing Stellite wear surfaces to the Existing Programs category. MRP 2018-022 escalated them to the Primary category.

Notes

1. Examination acceptance criteria and expansion criteria are in Table 5-3 of MRP-227 Rev. 1-A.
2. A minimum of 75% of the total identified sample population must be examined.
3. A minimum of 75% of the total population (examined + unexamined), including coverage consistent with the Expansion criteria in Table 5-3 of MRP-227 Rev. 1-A, must be examined from either the inner or outer diameter for inspection credit.
4. Void swelling effects on this component are managed through management of void swelling on the entire baffle-former assembly.
5. PBN baseline inspections have already been performed consistent with WCAP-17451-P, and the modified requirements due to the interim guidance provided in EPRI letter MRP 2018-007 dated 3/7/2018 and PWROG letter OG-18-46 dated 2/20/2018.
6. Examination coverage requires a minimum of 50% of the length of either the ID or the OD of the weld being examined.
7. Baffle-former bolt inspection includes inspection of the corner plate bolts when applicable.
8. In accordance with MRP 2017-009 and MRP 2017-010, PBN has completed the baseline UT examination prior to 35 EFPY.
9. Re-examination periods shall be determined by plant-specific evaluation per the MRP-227 Needed Requirement 7.5 as documented and dispositioned in the owner's plant corrective action program. If atypical or aggressive baffle-former bolt degradation as defined in MRP 2017-009 (i.e., ≥3% of baffle-former bolts with UT or visual indications or clustering* for downflow plants and ≥5% of baffle-former bolts with UT or visual indications or clustering* for upflow plants) is observed, the interim guidance (MRP 2016-021 and MRP 2017-009) provides limitations to the permitted reinspection interval (not to exceed 6 years maximum) unless further evaluation is performed to justify a longer interval (See Applicant/Licensee Action Item 1 in the NRC SE for evaluation submittal requirements). If evaluation justifies a longer reinspection interval, it is not permitted to exceed 10 years.

   *"Clustering" is defined per NSAL-16-1 Rev. 1 as three or more adjacent defective baffle-former bolts or more than 40% defective baffle-former bolts on the same baffle plate. Untestable bolts should be reviewed on a plant-specific basis consistent with WCAP-17096-NP-A for determination if these should be considered when evaluating clustering.

10. See Westinghouse Technical Bulletin TB-19-5 dated 10/9/2019 and MRP 2019-017 dated 5/31/2019 for additional details on inspection recommendations.
11. The clevis inserts are attached to integrally welded reactor vessel lugs and the inserts are bolted to the lugs. The ASME Code examination of accessible surfaces is considered to include all details of the clevis configuration, including the bolting and locking devices. The bolting is fabricated from nickel-based materials and is susceptible to stress corrosion cracking (SCC). Although failure of the bolting does not itself cause loss of support function, asset impairment or issues with core barrel removal are a subsequent possibility. Westinghouse technical bulletin TB 14-5 dated 8/25/2014 provides additional information regarding possible visual indications that clevis bolting failure may have occurred. This information should be reviewed to ensure a heightened awareness of the examiners is applied to this Code inspection.

Table C.A2 – Expansion Components

Item	Effect (Mechanism)	Primary Link (Note 1)	Examination Method/Frequency (Note 1)	Examination Coverage	Source of Revision / Addition
Control Rod Guide Tube Assembly W2.1.Remaining CRGT lower flange welds	Cracking (SCC, Fatigue) Aging Management (IE and TE)	W2.CRGT Lower Flange Welds	Enhanced visual (EVT-1) examination to determine the presence of crack-like surface flaws in flange welds. Subsequent examination on a ten-year interval.	A minimum of 75% of the CRGT assembly lower flange weld surfaces and a 0.25-inch of the adjacent base metal for the flange welds not inspected under the primary link.	MRP-227 Rev. 1-A added the requirement for 0.25 inch of adjacent base metal and added the coverage expansion to the Expansion category.
Bottom Mounted Instrumentation System W2.2.Bottom-mounted instrumentation (BMI) column bodies	Cracking (Fatigue) including the detection of completely fractured column bodies Aging Management (IE)	W2. CRGT lower flange welds	Visual (VT-3) examination. Re-inspection every 10 years following initial inspection.	100% of BMI column bodies for which difficulty is detected during flux thimble insertion/withdrawal. See Figures 13 and 15.	Rev. 1-A revised the examination frequency description.
Core Barrel Assembly W3.1.Upper girth weld (UGW)	Cracking (SCC)	W3.Upper core barrel flange weld (UFW)	Enhanced visual (EVT-1) examination. Reinspection every 10 years following initial inspection.	100% of the accessible weld length of one side of the UGW and 3/4" of adjacent base metal shall be examined (Notes 2 and 5).	Rev. 1-A added the UGW as Expansion Components linked to the UFW.
Core Barrel Assembly W3.2Upper axial weld (UAW)	Cracking (SCC)	W3.Upper core barrel flange weld (UFW)	Enhanced visual (EVT-1) examination. Reinspection every 10 years following initial inspection.	100% of the accessible weld length of one side of the UAW and 3/4" of adjacent base metal shall be examined (Notes 2 and 5).	Rev. 1-A added the UAW as Expansion Components linked to the UFW.
Core Barrel Assembly W3.3.Lower flange weld (LFW)	Cracking (SCC)	W3.Upper core barrel flange weld (UFW)	Enhanced visual (EVT-1) examination. Reinspection every 10 years following initial inspection.	100% of the accessible weld length of the OD surface of the LFW and 3/4" of adjacent base metal shall be examined (Note 5).	Rev. 1-A added the UAW and UGW as Expansion Components linked to the UFW.
Lower Internals Assembly W3.4.Lower support forging	Cracking (SCC)	W3.Upper core barrel flange weld (UFW)	Visual (VT-3) examination. Re-inspection every 10 years following initial inspection	Minimum of 25% of bottom (non-core side) surface (Note 3)	Rev. 1-A added this component to the Expansion Components.
Upper Internals Assembly W4.1Upper core plate	Cracking (Fatigue), Wear Aging Management (IE)	W4.Lower girth weld (LGW)	Visual (VT-3) examination. Re-inspection every 10 years following initial inspection	Minimum of 25% of core side surfaces (Note 3).	Rev. 1-A reduced examination coverage from 100% of accessible.

Table C.A2 – Expansion Components

Item	Effect (Mechanism)	Primary Link (Note 1)	Examination Method/Frequency (Note 1)	Examination Coverage	Source of Revision / Addition
Core Barrel Assembly W4.2.Middle Axial Welds (MAW) and W4.3.Lower Axial Welds (LAW)	Cracking (SCC, IASCC) Aging Management (IE)	W4.Lower girth weld (LGW)	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of the accessible weld length of the OD of the MAW and LAW and 3/4" of adjacent base metal shall be examined (Notes 5 and 6). See Figure 4	Rev. 1-A changed the component name to specify MAW and LAW, the examination coverage is updated so the OD is to be inspected and 3/4" of base metal.
Lower Support Assembly W4.4.Lower support column bodies (both cast and non cast)	Cracking (IASCC) Aging Management (IE)	W4.Lower girth weld (LGW)	Visual (VT-3) examination. Re-inspection every 10 years following initial inspection	25% of the total number of column assemblies (both visible and non-visible from above the lower core plate) using a VT-3 examination from above the lower core plate. The inspection coverage must be evenly distributed across the population of column assemblies. (Notes 3 and 4).	Rev. 1-A changed the Primary link to the LGW, updated the inspection technique to VT-3 and changed coverage from 100% of accessible surfaces. This item now groups cast and non cast lower support column bodies together. Primary link changed from CRGT lower flanges.
Core Barrel Assembly W6.1.Barrel-former bolts	Cracking (IASCC, Fatigue) Aging Management (IE, Void Swelling and ISR)	W6.Baffle-former bolts (also refer to MRP 2018-002)	Volumetric (UT) examination. Re-inspection every 10 years following initial inspection.	100% of accessible barrel-former bolts (Minimum of 75% of the total population). Accessibility may be limited by presence of thermal shields of neutron pads.	Rev. 1-A identified additional aging mechanisms, defined the reinspection interval and minimum examination coverage when accounting for inaccessible bolts.
Lower Support Assembly W6.2.Lower support column bolts	Cracking (IASCC, Fatigue) Aging Management (IE and ISR)	W6.Baffle-former bolts	Volumetric (UT) examination. Re-inspection every 10 years following initial inspection.	100% of accessible LSC bolts (Minimum of 75% of the total population) or as supported by plant-specific justification (Note 2).	Rev. 1-A identified additional aging mechanisms, defined the reinspection interval and minimum examination coverage when accounting for inaccessible bolts.
Core Barrel Assembly Core barrel outlet nozzle welds	Cracking (IASCC, Fatigue) Aging Management (IE of lower sections)	N/A	N/A	N/A	Rev. 1-A removed this component from the Expansion Components. This was previously linked to the UFW, which now links to the newly added UAW and UGW.

Notes

1. Examination acceptance criteria and expansion criteria are in Table 5-3 of MRP-227 Rev. 1-A.
2. Examination coverage requires examination of either the ID or the OD of the weld.
3. The stated minimum coverage requirement is the minimum if no significant indications are found. However, the Examination Acceptance criteria in Section 5 of MRP-227 Rev. 1-A require that additional coverage must be achieved in the same outage if significant flaws are found. This contingency should be considered for inspection planning purposes.
4. Justification that adequate distribution of the inspection coverage has been achieved can be based on geometric or layout arguments. Possible examples include, but are not limited to, inspection of all column assemblies in one quadrant of the lower core plate (based on the azimuthal symmetry of the plate) or inspecting every fourth column across the entire plate.
5. A minimum coverage of 75% of the weld length on the surface being examined shall be achieved; however, for welds with limited access (Note 6), a minimum examination coverage of 50% of the weld length on the surface being examined shall be achieved.
6. Accessibility to the MAW and LAW may be limited by the thermal shield or neutron panels – no disassembly to achieve higher weld length coverage is required.

Table C.A3 – Existing Programs Components

Item	Effect (Mechanism)	Reference	Examination Method	Examination Coverage	Source of Revision / Addition
W10.Core Barrel Assembly Core barrel flange	Loss of material (Wear)	ASME Code Section XI	Visual (VT-3) examination to determine general condition for excessive wear.	All accessible surfaces at specified frequency.	No changes.
W11.Upper Internals Assembly Upper support ring or skirt	Cracking (SCC, Fatigue)	N/A	N/A	N/A	This component is not applicable to PBN.
W12a.Lower Internals Assembly Lower core plate	Cracking (IASCC, Fatigue) Aging Management (IE)	ASME Code Section XI as supplemented by TB-16-4	Visual (VT-3) exam of the lower core plates to detect evidence of distortion and/or loss of bolt integrity.	All accessible surfaces at specified frequency.	TB-16-4 supplement added by MRP-227 Rev. 1-A.
W12b.Lower Internals Assembly Lower core plate	Loss of material (Wear)	ASME Code Section XI as supplemented by TB-16-4	Visual (VT-3) examination.	All accessible surfaces at specified frequency.	TB-16-4 supplement added by MRP-227 Rev. 1-A.
W13.Bottom Mounted Instrumentation System Flux thimble tubes	Loss of material (Wear)	IEB 88-09	Surface (ET) examination	Eddy current surface examination as defined in plant response to IEB 88-09.	IEB 88-09 added as Reference by MRP-227 Rev. 1-A
W15.Alignment and Interfacing Components Upper core plate alignment pins	Loss of material (Wear)	ASME Code Section XI as supplemented by TB-16-4	Visual (VT-3) examination	All accessible surfaces at specified frequency.	TB 16-4 supplement added by MRP-227 Rev. 1-A.
W16.UCP and Fuel Alignment Pins Fuel alignment pins	Loss of material (Wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency	Added per MRP 2018-022 recommendations.
W17.LCP and Fuel Alignment Pins Fuel alignment pins	Loss of material (Wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency	Added per MRP 2018-022 recommendations.

APPENDIX D

TECHNICAL SPECIFICATION CHANGES

The Code of Federal Regulations, Title 10 CFR 54.22, requires applicants to include any Technical Specification changes, or additions, necessary to manage the effects of aging during the subsequent period of extended operation as part of the renewal application. Based on a review of the information provided in the Point Beach Subsequent License Renewal Application and Technical Specifications, no Technical Specifications changes are being submitted with this Application.