Enclosure 3

St. Lucie Nuclear Plant Units 1 and 2

Subsequent License Renewal Application

(Public Version)

August 2021

Attachment 1

(1572 Total Pages, including cover sheets)

St. Lucie Nuclear Plant
Units 1 and 2
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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 St. Lucie Nuclear Plant Unit 1 (DPR-67) (Reference 1.6.2) and Unit 2 (NPF-16) (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 St. Lucie Nuclear Plant 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

St. Lucie Nuclear Plant (PSL) Unit 1 is wholly owned and operated by the Florida Power & Light Company (FPL). PSL Unit 2 is owned, in part, by the Orlando Utilities Commission of the City of Orlando, Florida (≈6.1%), and the Florida Municipal Power Agency (FMPA) (≈8.8%). However, FPL is the majority owner (≈85.1%) and is authorized to act as agent for the Orlando Utilities Commission and the Florida Municipal Power Agency and has exclusive responsibility and control over the physical construction, operation, and maintenance of the facility.

FPL hereby applies for subsequent renewed operating licenses for PSL Units 1 and 2. FPL is based in Juno Beach, Florida and is the licensed operator of PSL, Units 1 and 2.

1.1.2 Address of Applicant

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819-9002

Orlando Utilities Commission
100 West Anderson Street
Orlando, Florida 32801-4408

Address of the St. Lucie Nuclear Plant:

Florida Power & Light Company
St. Lucie Nuclear Plant
6501 S. Ocean Drive
Jensen Beach, Florida 34957-2000

1.1.3 Organization and Management of Applicant

FPL is a public utility incorporated under the laws of the State of Florida, with its principal office located in Juno Beach, Florida.

FPL is not owned, controlled, or dominated by any alien, foreign corporation, or foreign government.

The names and business addresses of FPL's, FMPA's, and OUC's directors and principal officers are listed below. All persons listed are U.S. citizens.

FPL Names and Addresses of the Directors		
Name	Title	Address
James L. Robo	Chairman of the Board	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420
Eric E. Silagy	President and Chief Executive Officer	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420
Rebecca J. Kujawa	Executive Vice President, Finance and Chief Financial Officer	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420

FPL Names and Addresses of the Principal Officers		
Name	Title	Address
James L. Robo	Chairman of the Board	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420
Eric E. Silagy	President and Chief Executive Officer	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420
Rebecca J. Kujawa	Executive Vice President, Finance and Chief Financial Officer	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420

FPL Names and Addresses of the Principal Officers		
Name	Title	Address
Paul I. Cutler	Treasurer	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420
W. Scott Seeley	Vice President, Compliance & Corporate Secretary	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420
Miguel Arechabala	Executive Vice President, Power Generation Division	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420
Manuel B. Miranda	Senior Vice President, Power Delivery	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420
Robert Coffey	Executive Vice President Nuclear Division &Chief Nuclear Officer	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420

FMPA Names and Addresses of the Directors		
Name	Title	Address
Barbara Quiñones	Chair of the Board	Homestead Energy, 675 N. Flagler Ave. Homestead, FL 33030-6173
Lynne Tejeda	Vice Chair	P. O. Box 6100, Key West, FL 33041-6100
Larry Mattern	Secretary	Kissimmee Utility Auth., 1701 W. Carroll St., Kissimmee, FL 34741
Allen Putnam	Treasurer	Beaches Energy Services, 11 3rd St. N., Jacksonville Beach, FL 32250

FMPA Names and Addresses of the Principal Officers		
Name	Title	Address
Jacob A. Williams	General Manager & Chief Executive Officer	8553 Commodity Circle, Orlando, FL 32819
Ken Rutter	Chief Operation Officer	8553 Commodity Circle, Orlando, FL 32819
Linda S. Howard	Chief Financial Officer	8553 Commodity Circle, Orlando, FL 32819
Mark McCain	Vice President, Vice President, Member Services & Public Relations	8553 Commodity Circle, Orlando, FL 32819

FMPA Names and Addresses of the Principal Officers		
Name	Title	Address
Sharon Adams	Vice President, Human Resources & Shared Services	8553 Commodity Circle, Orlando, FL 32819
Jody Lamar Finklea	General Counsel	2061-2 Delta Way, Tallahassee, FL 32303

OUC Names and Addresses of the Principal Officers		
Name	Title	Address
Clint Bullock	General Manager & Chief Executive Officer	100 West Anderson Street Orlando, Florida 32801-4408
Jan Aspuru	Chief Operation Officer	100 West Anderson Street Orlando, Florida 32801-4408
Chris Browder	Chief Legal Officer	100 West Anderson Street Orlando, Florida 32801-4408
Latisha Thompson	Chief Employee Experience Officer	100 West Anderson Street Orlando, Florida 32801-4408
Mindy Brenay	Chief Financial Officer	100 West Anderson Street Orlando, Florida 32801-4408
Manju Palakkat	Chief Transformation and Technology Officer	100 West Anderson Street Orlando, Florida 32801-4408
Linda Ferrone	Chief Customer and Marketing Officer	100 West Anderson Street Orlando, Florida 32801-4408

OUC Names and Addresses of the Commissioners		
Name	Title	Address
Britta Gross	President	100 West Anderson Street Orlando, Florida 32801-4408
Cesar Calvet	Commissioner	100 West Anderson Street Orlando, Florida 32801-4408
Greg Lee	Commissioner	100 West Anderson Street Orlando, Florida 32801-4408
Larry Mills	Commissioner	100 West Anderson Street Orlando, Florida 32801-4408
Buddy Dyer	Mayor/Commissioner	100 West Anderson Street Orlando, Florida 32801-4408

1.1.4 Class of License, the Use of the Facility, and the Period of Time for which the License is Sought

FPL requests subsequent renewal of the operating licenses issued under Sections 104b and 103 of the Atomic Energy Act of 1954, as amended, for PSL Unit 1 and Unit 2 (License Nos. DPR-67 and NPF-16, respectively), for a period of 20 years beyond the expiration of the current renewed operating licenses. In addition, because this SLRA is being presented with more than 20 years remaining on operating license NPF-16 for PSL Unit 2, FPL requested a one-time exemption of the application timing rule in 10 CFR 54.17(c) for Unit 2 in FPL letter L-2021-063 dated March 17, 2021 (Reference ML21076A314). The NRC granted the one-time exemption in NRC letter dated July 20, 2021 (Reference ML21165A027). This SLRA would extend the renewed operating license for PSL Unit 1 from midnight on March 01, 2036, to midnight March 01, 2056, and PSL Unit 2 renewed operating license from midnight on April 06, 2043, to midnight on April 06, 2063. Finally, 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 St. Lucie Nuclear Plant Units 1 and 2 and will continue to generate electric power during the subsequent license renewal (SLR) period.

1.1.5 Earliest and Latest Dates for Alterations

FPL 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.

1.1.6 Regulatory Agencies with Jurisdiction

Regulatory agencies with jurisdiction over the PSL revenue are:

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

Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

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

1.1.7 Local News Publications

News publications that circulate in the area surrounding the PSL Units 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:

The Tribune
600 Edwards Road
Fort Pierce, Florida 34982-6295
561-461-2050
Fax-561-461-4447

Okeechobee News
107 SW 17th Street, Suite D
Okeechobee, Florida 34974-6110
941-763-3134
Fax-941-763-5901

The Stuart News
1939 SE Federal Highway
Stuart, Florida 34994-3915
561-287-1550
Fax-561-221-4246

The Port St. Lucie News
1932 SE Port St. Lucie Blvd.
Port St. Lucie, Florida 34952-5509
561-337-5800
Fax-561-335-0877

Vero Beach Press Journal
1801 US Highway 1
Vero Beach, Florida 32960-0997
561-562-2315
Fax-561-978-2364

The Palm Beach Post
2751 South Dixie Highway
West Palm Beach, Florida 33405-1298
561-820-4100
Fax-561-820-4407

1.1.8 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 (B-76) for PSL 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. 10, lists four license numbers. FPL has reviewed the original Indemnity Agreement and the Amendments. Neither Article VII nor Item 3 of the Attachment specifies an expiration date for license numbers DPR-67 or NPF-16. Therefore, no changes to the Indemnity Agreement are deemed necessary as part of this SLRA. Should the license numbers be changed upon issuance of the subsequent renewed licenses, FPL requests that conforming changes be made to Item 3 of the Attachment, and any other sections of the indemnity agreement as appropriate.

1.1.9 Descriptions of Business or Occupation of Applicant

FPL is an investor-owned utility, primarily engaged in the generation, transmission, and distribution of electricity. The service territory covers the southern third and almost the entire eastern seaboard of the State of Florida, plus the western panhandle region of Florida that has been served by the former Gulf Power Company that has been acquired by FPL's parent company, NextEra Energy. FPL and Gulf Power Company have now been merged into a single utility company under the Florida Power & Light name.

As of year-end 2020, the generating system for the merged utility system consisted of the following units that are fully and/or partially owned by FPL/Gulf: 4 nuclear units (including the PSL units), 16 combined cycle units, 13 simple cycle combustion turbine units, 4 gas turbines, 2 gas/oil steam units, 8 coal steam units, 2 landfill gas units, and 32 solar photovoltaic units. The total firm generating capacity (Summer MW) from these facilities, including PSL, is 28,496 MW.

Florida Municipal Power Agency (FMPA) is a nonprofit, joint action agency formed by thirty-one (31) municipal electric utilities, serving approximately 2.6 million customers in the State of Florida.

Orlando Utilities Commission (OUC) is a statutory municipal utility providing water and electric service to the City of Orlando and adjoining portions of Orange County. OUC currently serves 224,046 electric customers in the entire City of Orlando, a portion of unincorporated Orange County, and the City of St. Cloud.

The current PSL Units operating licenses will expire as follows:

- At midnight on March 01, 2036, for PSL Unit 1 (Renewed Facility Operating License No. DPR-67)
- At midnight on April 06, 2043, for PSL Unit 2 (Renewed Facility Operating License No. NPF-16)

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

1.1.10 <u>Restricted Data Agreement</u>

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 PSL 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

PSL is a steam electric generating facility situated on the East Coast of Florida, approximately seven miles southeast of the city of Fort Pierce, Florida. The plant consists of two nuclear power Units designated as PSL Unit 1 and PSL Unit 2.

The PSL Units 1 and 2 reactors are Combustion Engineering designed pressurized light-water moderated and cooled systems. PSL Units 1 and 2 were each originally licensed and operated at 2560 megawatts thermal (MWt). Commercial operation for Unit 1 began on March 01, 1976, and for Unit 2 on April 06, 1983. Both Units' operating licenses were subsequently amended to allow operation at the stretch power limit of 2700 MWt (Unit 1 Amendment #48 dated November 23, 1981 (Reference ML013530273); Unit 2 Amendment #9 dated March 1, 1985 (Reference ML013600080).

In 2012, an extended power uprate (EPU) increased the reactor core thermal power to 3020 MWt for each unit (References ML103560419, ML110730116, and ML12124A224). For each unit, both original steam generators were removed and replacement steam generators designed and manufactured by B&W (Unit 1) and AREVA (Unit 2) were installed. Per the Unit 1 and Unit 2 UFSAR, each steam and power conversion system, including its turbine generator, is designed to permit generation of a gross electrical output of approximately 1026 megawatts-electric (MWe) for Unit 1 and 1045 MWe for Unit 2.

The major structures for PSL are two reactor containment buildings, two reactor auxiliary buildings, two turbine buildings, and two fuel handling buildings; it is one set of buildings for each unit. Each containment is a steel containment vessel with cylindrical shell surrounded by a reinforced concrete shield building.

FPL 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 of 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*, 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 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.

PSL 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:

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 appropriate reference to the Section 3 table providing the AMR results is made.

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 and instrumentation and control 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 4.0 also confirms that one plant-specific exemption granted pursuant to 10 CFR 50.12 was identified for each PSL Unit that is based upon a TLAA, as defined in 10 CFR 54.3.

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 19-3 of Appendix A1 and Table 19-3 of Appendix A2 of this SLRA; the information in Appendix A is intended to fulfill the requirements of 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. Plant-specific AMPs, if needed, are included in these sections, and evaluated using the guidance in Appendix A of NUREG-2192, Section A.1.2.3, Aging Management Program 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 PSL Reactor Vessel Internals Program based on the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) Topical Report No. 3002017168, Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A) (Reference ML20175A112)-- 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 as necessary to manage the effects of aging during the SPEO.

Appendix E - Environmental Information – St. Lucie 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 PSL 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), PSL 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
Florida Power & Light Company
15430 Endeavor Dr.
Jupiter, FL, 33478

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-67, PSL Renewed Facility Operating License for St. Lucie Nuclear Plant Unit 1, ADAMS Accession No. ML052790654, October 2, 2003.

1.6.3 NPF-16, PSL Renewed Facility Operating License for St. Lucie Nuclear Plant Unit 2, ADAMS Accession No. ML052800077, October 2, 2003.

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 RG 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 "Application for Renewed Operating Licenses St. Lucie Nuclear Plant Units 1 & 2", November 29, 2001. ADAMS Accession No. ML013400155.

1.6.14 EPRI TR 3002002850, Steam Generator Management Program: Investigation of Crack Initiation and Propagation in the Steam Generator Channel Head Assembly, Electric Power Research Institute, October 2014.

1.6.15 RG 1.190, "Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," March, 2002. ADAMS Accession No. ML010890301.

1.6.16 GSI-15, “Resolution of Generic Safety Issues: Issue 15: Radiation Effects on Reactor Vessel Supports (Rev. 3) (NUREG-0933, Main Report with Supplements 1–34).”

1.6.17 NUREG-1509, Radiation Effects on Reactor Pressure Vessel Supports”, May 22, 1996.

1.6.18 NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” July 1980. ADAMS Accession No. ML070250180.

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

1.6.20 NEI 14-12, Revision 1, “Aging Management Program Effectiveness,” September 2020.

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

1.6.22 EPRI 3002000505, Revision 7, “Pressurized Water Reactor Primary Water Chemistry Guidelines.”

1.6.23 EPRI 3002010645, Revision 8, “Pressurized Water Reactor Secondary Water Chemistry Guidelines”.

1.6.24 RG 1.65, Revision 1, "Materials and Inspections for Reactor Vessel Closure Studs".

1.6.25 GL 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants”.

1.6.26 NEI 03-08, Revision 3, “Guideline for the Management of Materials Issues”.

1.6.27 EPRI NSAC-202L-R4, “Recommendations for an Effective Flow-Accelerated Corrosion Program,” November 2013.

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

1.6.29 EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” April 1988.

1.6.30 EPRI Report 1015336, “Nuclear Maintenance Application Center: Bolted Joint Fundamentals,” December 2007.

1.6.31 EPRI Report 1015337, “Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints,” December 2007.

1.6.32 NEI 97-06, Revision 3, “Steam Generator Program Guidelines.” ADAMS Accession No. ML111310708.

1.6.33 EPRI 3002007572, Revision 8, “PWR Steam Generator Examination Guidelines”.

1.6.34 EPRI 1022832, Revision 4, “PWR Primary-to-Secondary Leak Guidelines”.

1.6.35 EPRI 3002007571, Revision 4, “Steam Generator Integrity Assessment Guidelines”.

1.6.36 EPRI 3002007856, Revision 5, “Steam Generator In-Situ Pressure Test Guidelines”.

1.6.37 GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” U.S. Nuclear Regulatory Commission, Washington D.C., July 1989.

1.6.38 S9086-CQ-STM-010, Revision 5, Naval Ships’ Technical Manual, Chapter 081, “Waterborne Underwater Hull Cleaning of Navy Ships,” Naval Sea Systems Command, October 2006.

1.6.39 EPRI TR-3002000590, Revision 2, “Closed Cooling Water Chemistry Guideline,” December 2013.

1.6.40 NFPA 25, “Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” Quincy, Massachusetts, National Fire Protection Association, 2011.

1.6.41 ASTM D975-06, Standard Specification for Diesel Fuel Oils.

1.6.42 EPRI, TR-1007933, “Aging Assessment Field Guide,” December 2003.

1.6.43 EPRI, TR-1009743, “Aging Identification and Assessment Checklist: Mechanical Components,” August 2004.

1.6.44 RG 1.54, “Revision 3, Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.” ADAMS Accession No. ML17031A288, U.S. Nuclear Regulatory Commission, Washington, DC, April 2017

1.6.45 ASTM D5163-08, “Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants.” West Conshohocken, Pennsylvania: American Society for Testing and Materials. 2008

1.6.46 ASTM D5498-12, “Standard Guide for Developing a Training Program for Personnel Performing Coating and Lining Work Inspection for Nuclear Facilities.”

1.6.47 Structural Integrity Report No. 2001262.401, Revision 1, “Flaw Tolerance Evaluation of St. Lucie, Units 1 and 2 Surge Line Using ASME Code, Section XI, Appendix L for Subsequent License Renewal,” July 15, 2021. (Enclosure 4, Attachment 16).

1.7 ACRONYMS

Table 1.7-1
Acronyms

Acronym	Description
A/C	Air Conditioning
AC	Alternating Current
AAC	Alternate AC
AAAC	All Aluminum Alloy Conductor
ACE	Apparent Cause Evaluation
ACI	American Concrete Institute
ACR	Alkali-Carbonate Reaction
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
ANSI	American National Standards Institute
AOP	Abnormal Operating Procedure
AOV	Air Operated Valve
API	American Petroleum Institute
AR	Action Request or Aspect Ratio
ARM	Area Radiation Monitor
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASR	Alkali-Silicate Reaction
AST	Alternate Source Team
ASTM	American Society for Testing and Materials
ATWS	Anticipated Transients Without Scram
AVB	Anti-Vibration Bars
A690TT	Thermally Treated Alloy 690
BAC	Boric Acid Corrosion
BACC	Boric Acid Corrosion Control

Table 1.7-1
Acronyms

Acronym	Description
BSW	Biological Shield Wall
BTP	Branch Technical Position
B&W	Babcock and Wilcox
BWI	Babcock and Wilcox International
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
CCCW	Closed-Cycle Cooling Water
CCMP	Cable Condition Monitoring Program
CCW	Component Cooling Water
CDBI	Component Design Basis Inspection
CE	Combustion Engineering
CEA	Control Element Assembly
CEDM	Control Element Drive Mechanism
CEOG	CE Owners Group
CFR	Code of Federal Regulations
CHRRMS	Containment High Range Radiation Monitor System
CLB	Current Licensing Basis
CMAA	Crane Manufacturers Association of America
CMTR	Certified Material Test Report
CPE	Chlorinated Polyethylene
CPVC	Chlorinated Polyvinyl Chloride
CR	Condition Report
CRD	Control Rod Drive
CRDM	Control Rod Drive Mechanism
CS	Containment Spray
CSA	Core Shroud Assembly
CSB	Core Shroud Bolting
CSE	Copper/Copper Sulfate Reference Electrode

Table 1.7-1
Acronyms

Acronym	Description
CST	Condensate Storage Tank
CTWS	Closed Treated Water System
CUF	Cumulative Usage Factor
CUF_{en}	Cumulative Usage Environmental Factor
CVCS	Chemical and Volume Control System
CWST	City Water Storage Tank
DA	Degradation Assessment
DAFAS	Diverse Auxiliary Feedwater Actuation System
DBA	Design Basis Accident or Design Basis Assurance
DBD	Design Basis Document
DBE	Design Basis Event
DC	Direct Current
DG	Diesel Generator
DM	Dissimilar Metal
DMW	Dissimilar Metal Weld
DOR	Division of Operating Reactors
DOST	Diesel Oil Storage Tank
dpa	Displacements per Iron Atom
DSS	Diverse Scram System
DTT	Diverse Turbine Trip
DW	Demineralized Makeup Water
EAF	Environmentally Assisted Fatigue
EC	Engineering Change
ECB	Electrical Catch Basin
ECC	Emergency Cooling Canal
ECCS	Emergency Core Cooling System
ECP	Electrochemical Potential
ECT	Eddy Current Testing
EDG	Emergency Diesel Generator
EDGCW	Emergency Diesel Generator Cooling Water
EDMS	Electronic Document Management System

Table 1.7-1
Acronyms

Acronym	Description
EFPY	Effective Full Power Years
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
EPRI-MRP	Electric Power Research Institute Materials Reliability Program
EPU	Extended Power Uprate
EQ	Environmental Qualification or Environmentally Qualified
ER	Environmental Report
ESE	Erosion Susceptibility Evaluation
ESF	Engineered Safety Feature
ETSS	Eddy Current Technique Specification Sheet
F (°F)	Degrees Fahrenheit
FAC	Flow-Accelerated Corrosion
F_{en}	Environmental Fatigue Correction Factor
FERC	Federal Energy Regulatory Commission
FHB	Fuel Handling Building
FLEX	Diverse and Flexible Mitigation Capability
FMECA	Failure Mode, Effects and Criticality Analysis
FMP	Fatigue Monitoring Program
FMPA	Florida Municipal Power Association
FOSAR	Foreign Object Search and Retrieval
FP	Fire Protection
FPL	Florida Power & Light Company
FR	Fouling Rating
FSAR	Final Safety Analysis Report
FSRF	Fatigue Strength Reduction Factor
ft-lb	Foot-Pound
FW	Feedwater
GALL	Generic Aging Lessons Learned
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GL	Generic Letter
GSI	Generic Safety Issue

Table 1.7-1
Acronyms

Acronym	Description
HELB	High Energy Line Break
HVAC	Heating, Ventilation, and Air Conditioning
HX	Heat Exchanger
IA	Instrument Air
IASCC	Irradiation Assisted Stress Corrosion Cracking
I&C	Instrumentation and Controls
ICW	Intake Cooling Water
IE	Irradiation Embrittlement
I&E	Inspection and Examination
IEB	Inspection and Enforcement Bulletin
IEEE	Institute of Electrical and Electronics Engineers
IFD	Incipient Fire Detection
IGSCC	Intergranular Stress Corrosion Cracking
ILRT	Integrated Leak Rate Test
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IP	Inspection Procedure
IPA	Integrated Plant Assessment
IR	Interaction Ratio or Insulation Resistance
ISA	International Society of Automation
ISFSI	Independent Spent Fuel Storage Installation
ISG	Interim Staff Guidance
ISI	In-service Inspection
iso	Isometric
K	Unintentional Curvature
ksi	Kilo-pounds per Square Inch
kV	Kilovolts
kW	Kilowatts
LAW	Lower Axial Weld
LBB	Leak-Before-Break
LER	Licensee Event Report

Table 1.7-1
Acronyms

Acronym	Description
LFET	Low-Frequency Electromagnetic Testing
LLRT	Local Leak Rate Test
LOCA	Loss of Coolant Accident
LR	License Renewal
LRA	License Renewal Application
LTOP	Low Temperature Overpressure Protection
L-V	Low-Voltage
L1A	Level 1 Assessment
LWR	Light Water Reactor
MAW	Middle Axial Weld
MCM	Thousands of Circular Mils
MEB	Metal Enclosed Bus
MeV	Million Electron Volts
MFIV	Main Feedwater Isolation Valve
MG	Motor Generator
MoS_2	Molybdenum Disulfide
MOV	Motor Operated Valve
MPa	Megapascal
MRFF	Maintenance Rule Functional Failure
MRP	Material Reliability Program
MSIV	Main Steam Isolation Valve
MSLB	Main Steam Line Break
MSR	Moisture Separator Reheater
MW	Megawatts
MWe	Megawatts Electric
MWt	Megawatts Thermal
MV	Medium-Voltage
NACE	National Association of Corrosion Engineers
NAMS	Nuclear Asset Management Suite
NaOH	Sodium Hydroxide
NCV	Non-Cited Violation

Table 1.7-1
Acronyms

Acronym	Description
NDE	Nondestructive Examination
NEE	NextEra Energy
NEI	Nuclear Energy Institute
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
Ni	Nickel
NNS	Nonsafety-Related
NPO	Non-power Operations
NPS	Nominal Pipe Size
NRC	U. S. Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSB	Non-Segregated Bus
NSCA	Nuclear Safety Capability Assessment
NSSS	Nuclear Steam Supply System
NTTF	Near Term Task Force
NUGEQ	Nuclear Utility Group on Equipment Qualification
NUMARC	Nuclear Management and Resources Council
NUREG	U.S. Nuclear Regulatory Commission Technical Report Designation
OAR	Owner's Activity Report
ODSCC	Outer Diameter Stress Corrosion Cracking
OE	Operating Experience
OEM	Original Equipment Manufacturer
OLAMST	Outdoor and Large Atmospheric Metallic Storage Tank
OUC	Orlando Utilities Commission
P&C	Protection and Control
PEO	Period of Extended Operation
PH	Precipitation-Hardened
P&ID	Piping and Instrument Diagram
PM	Preventative Maintenance
PMRQ	Preventative Maintenance Requirement

Table 1.7-1
Acronyms

Acronym	Description
PMW	Primary Makeup Water
PORV	Power Operated Relief Valve
PS	Plant Sampling
PSL	St. Lucie Nuclear Plant Units 1 and 2
PSPM	Periodic Surveillance and Preventative Maintenance Program
PSW	Primary Shield Wall
P-T	Pressure – Temperature
PTS	Pressurized Thermal Shock
PVC	Polyvinyl Chloride
PWR	Pressurized Water Reactor
PWROG	Pressurized Water Reactor Owners Group
PWSCC	Primary Water Stress Corrosion Cracking
PWST	Primary Water Storage Tank
QA	Quality Assurance
QHSA	Quick Hit Self-Assessment
QL	Quality Level
Q1	First Quarter
Q4	Fourth Quarter
RAI	Request for Additional Information
RAB	Reactor Auxiliary Building
RCP	Reactor Coolant Pump
RCPB	Reactor Coolant Pressure Boundary
RCPOCS	Reactor Coolant Pump Oil Collection System
RCS	Reactor Coolant System
RCSC	Research Council for Structural Connections
RFO	Refueling Outage
RG	Regulatory Guide
RIS	Regulatory Information Summary
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RSG	Replacement Steam Generator

Table 1.7-1
Acronyms

Acronym	Description
RT_{NDT}	Reference Temperature – NIL Ductility Transition
RT_{PTS}	Reference Temperature – Pressurized Thermal Shock
RV	Reactor Vessel
RVI	Reactor Vessel Internals
RVLMS	Reactor Vessel Level Monitoring System
RVUH	Reactor Vessel Upper Head
RWT	Refueling Water Tank or Routine Work Tracker
SBO	Station Black-out
SC	Structures and Components
SCC	Stress Corrosion Cracking
SE	Safety Evaluation
SEI	Structural Engineering Institute
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SGBD	Steam Generator Blowdown
SGIP	Steam Generator Integrity Program
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SIA	Structural Integrity Associates, Inc.
SIAS	Safety Injection Actuation Signal
SLR	Subsequent License Renewal
SLRA	Subsequent License Renewal Application
SLRBD	Subsequent License Renewal Boundary Drawing
SO_2	Sulfur Dioxide
SOER	Significant Operating Experience Report
SPEO	Subsequent Period of Extended Operation
SPS	Surry Power Station
SR	Silicone rubber
SRP	Standard Review Plan
SRP-SLR	Standard Review Plan for Subsequent License Renewal
SS	Stainless Steel

Table 1.7-1
Acronyms

Acronym	Description
SSA	Safe Shutdown Analysis
SSC	Systems, Structures, and Components
SW	Service Water
TB	Technical Bulletin
TCW	Turbine Cooling Water
TID	Total Integrated Dose
TLAA	Time-Limited Aging Analysis
TLO	Turbine Lubricating Oil
TMI	Three Mile Island
TR	Technical Report
TRM	Technical Requirements Manual
TS	Technical Specification
TSP	Trisodium Phosphate
TVA	Tennessee Valley Authority
TWST	Treated Water Storage Tank
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
URI	Unresolved Item
USE	Upper Shelf Energy
USI	Unresolved Safety Issue
UT	Ultrasonic Testing
UV	Ultraviolet
U1	Unit 1
U2	Unit 2
V	Volts
VDC	Voltage Direct Current
VS	Void Swelling
W	Weight
WCAP	Westinghouse Commercial Atomic Power
WEC	Westinghouse Energy Corporation
WO	Work Order

Table 1.7-1
Acronyms

Acronym	Description
WR	Work Request
Zn	Zinc

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 aging management review (AMR) in the PSL 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 PSL 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 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 PSL Units 1 and 2 SLR project. 10 CFR 54.21 requires that each SLRA contain an 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 SSCs in the scope of the rule;
2. Identifying the structures and components subject to aging management review; and
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 PSL license renewal (LR) project is described in Section 2 of the PSL original license renewal application (Reference 1.6.13). 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 (SR) function, if failure of the systems or structures prevent performance of a SR 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, the system 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 aging management review (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 and instrumentation and control commodities were evaluated collectively.

2.1.2 Information Sources Used for Scoping and Screening

In addition to the PSL Updated Final Safety Analysis Reports (UFSARs), Technical Specifications and Technical Requirements Manuals (TRM), the following additional CLB and other information sources were relied upon to a great extent in performing scoping and screening for PSL Units 1 and 2. A brief discussion of these sources is provided.

2.1.2.1 Design Basis Documents

The PSL Design Basis Documents (DBDs) were prepared for a number of PSL Unit 1 and 2 support and accident mitigation systems, selected licensing issues (including license renewal), and UFSAR Chapter 15 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 PSL 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 SLRA is current with NAMS as of October 1, 2020.

2.1.2.3 Plant Drawings

PSL 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 PSL mechanical systems, all applicable piping and instrumentation diagrams (P&IDs) were reviewed to identify the specific system boundaries included in the scope of SLR.

2.1.2.4 Fire Protection Nuclear Safety Capability Assessment

The PSL NFPA 805 Nuclear Safety Capability Assessment (NSCA) 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 SR and/or already included within the scope of SLR.

2.1.2.5 Station Blackout Equipment Lists

Equipment relied upon to mitigate a SBO event at PSL Unit 1 is described in Sections 8.3.1 and 15.2.13 of the Unit 1 UFSAR. Equipment relied upon to mitigate a SBO event at PSL Unit 2 is described in Sections 8.3.1 and 15.10 of the Unit 2 UFSAR. These documents were used to identify components and equipment credited for SBO that were not classified as SR 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 PSL Unit 1 and 2 Environmental Qualification (EQ) Master Lists provide a detailed listing of all equipment and components that must be environmentally qualified for use in a harsh environment. The PSL EQ Master Lists were used to identify equipment that must meet specific environmental qualification requirements.

2.1.2.7 Original License Renewal Documents

Documentation from the original license renewal application (LRA) for PSL 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 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, St. Lucie Units 1 and 2 and related docketed regulatory correspondence.
- NUREG-1779, Safety Evaluation Report Related to the License Renewal of the St. Lucie Nuclear Plant, Units 1 and 2.
- NRC Safety Evaluation Reports including NRC staff review of PSL licensing submittals.
- Licensing correspondence including relief requests, Licensee Event Reports, and responses to NRC communications such as NRC bulletins, generic

letters, or enforcement actions. Some of these documents may contain licensee commitments.

- Engineering evaluations, calculations, and design change packages which can provide additional information about the requirements and/or 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 2.0. 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 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) is performed on systems and structures using documents that form the CLB and other information sources. The CLBs for PSL Units 1 and 2 have been defined in accordance with the definition provided in 10 CFR 54.3. The key information sources that form the CLBs for PSL Units 1 and 2 include the UFSARs, Technical Specifications, and the docketed licensing correspondence. Other important information sources used for scoping are further described in Section 2.1.2.

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 3.2, 3.3, and 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 PSL, a 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 PSL SLR systems and structures is based on the guidance provided in NEI 17-01.

Certain structures and equipment were excluded at the outset because they are not considered to be SSCs that are part of the CLBs for PSL Units 1 and 2 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.

The systems and structures are grouped into the following categories, consistent with the grouping categories established in NUREG-2191:

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

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 the 10 CFR 54.4(a)(1) scoping criteria. The NAMS component database identifies SR components in a configuration controlled data field. In accordance with PSL plant procedures, SR 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 SR components have been excluded from the scope of SLR.

In 2012, the NRC issued license amendments supported by a Safety Evaluation Reports (SERs) (References ML12235A463 and ML12235A463) accepting the PSL Unit 1 and 2 implementation of alternate source term (AST) methodology; therefore, the requirements of 10 CFR 50.67 are applicable to PSL. However, no new electrical components were added to the PSL 10 CFR 50.49 program as a result of the AST adoption and 10 CFR 50.67 was not adopted for the environmental qualification of electrical equipment.

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 PSL Units 1 and 2 CLBs are consistent with 10 CFR 50.49(b)(1). Chapter 15 of both the PSL Units 1 and 2 UFSARs provide the DBE accident analyses for each unit.

Natural phenomena and external events are described in Chapter 3 of both the PSL Unit 1 and 2 UFSARs. Structures designed to withstand DBEs, natural phenomena, and external events are also described in Chapter 3 of both the PSL Unit 1 and 2 UFSARs.

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

- The UFSARs, Technical Specifications, TRMs, 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 SR.

The scoping process to identify SR systems and structures for PSL Unit 1 and 2 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 NNS SSCs whose failure could prevent satisfactory accomplishment of the functions identified for SR 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, Revision 6, Appendix F, for industry guidance related to 10 CFR 54.4(a)(2) scoping criteria.

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

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

The first item includes NNS SSCs credited as mitigative design features or for providing system functions relied on by SR SSCs in the PSL Units 1 and 2 CLBs. These NNS SSCs are identified by reviewing the PSL Unit 1 and 2 UFSARs and other CLB documents. In addition, a supporting system review was performed to identify any NNS systems that supports a SR intended function of a system included within the scope of SLR in accordance with 10 CFR 54.4(a)(1). Any NNS 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 NNS systems with the potential for physical or spatial interaction with SR SSCs. Scoping of these systems is the subject of NEI 95-10, Revision 6, Appendix F. Additional detail on the application of the 10 CR 54.4(a)(2) scoping criterion is provided in Section 2.1.4.2.

The scoping process to identify NNS systems and structures that can affect SR systems and structures for PSL Unit 1 and 2 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)
- Environmental Qualification (EQ) (10 CFR 50.49)
- Pressurized Thermal Shock (PTS) (10 CFR 50.61)
- Anticipated Transients Without Scram (ATWS) (10 CFR 50.62)
- Station Blackout (SBO) (10 CFR 50.63)

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 PSL 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.

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. The definition of a “Safe and Stable” condition is consistent with the nuclear safety performance criteria documented in NFPA 805, Section 1.5.1. 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 PSL Unit 1 and 2 NSCA Essential Equipment List is included in the NFPA 805 NSCA and provides the list of equipment necessary to bring the plant to a “Safe and

Stable" condition as determined by the fire SSA 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 PSL that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSAR, Technical Specifications, TRMs, NFPA 805 NSCA Essential 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 PSL Units 1 and 2 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 SR 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 PSL Unit 1 and 2 EQ Lists for 10 CFR 50.49, which state:

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 PSL that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSARs, Technical Specifications, TRMs, Environmental Qualification DBDs, Environmental Qualification (EQ) Lists, 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 PSL Unit 1 and 2 is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3). TLAAs associated with environmentally qualified equipment are discussed in Section 4.4.

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 PSL Units 1 and 2 CLBs show that the reactor vessels have been demonstrated to meet the toughness requirements of 10 CFR 50.61 through their current 60-year end-of-license period. The PSL Units 1 and 2 PTS time-limited aging analyses (TLAAs) discussed in Section 4.2.2 demonstrate that the fracture toughness requirements of 10 CFR 50.61 are met for the 80-year end-of-subsequent-license renewal period for each unit.

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

- The UFSARs, Technical Specifications, TRMs 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 SPEO.

The scoping process to identify systems and structures relied upon and/or specifically committed to for PTS for PSL Unit 1 and 2 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 PSL by the addition of two methodologies for ensuring that an excessive primary coolant pressure excursion does not occur. These methodologies are called "prevention" and "mitigation." Prevention takes form as a Diverse Scram System (DSS) whose purpose is to initiate a shutdown of the reactor by control rod insertion upon conditions indicative of an anticipated transient, independently, and diversely from the reactor protection system (RPS). Mitigation is accomplished by tripping the turbine and initiating auxiliary feedwater to conserve steam generator inventory and to ensure that a primary coolant heat sink is available. As required by the ATWS rule, both the diverse turbine trip (DTT) and the Diverse Auxiliary Feedwater Actuation System (DAFAS) initiation were also required to be diverse from the RPS. Through these diverse means of prevention and mitigation, peak reactor coolant system pressure will remain within acceptable values.

The PSL design features related to ATWS events are described in detail in Unit 1 UFSAR Section 7.6.1.4 and Unit 2 UFSAR Section 7.6.3.11.

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

- The UFSARs, Technical Specifications, TRMs, 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 PSL Unit 1 and 2 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.

PSL Unit 1 is an alternate AC (AAC) plant. Unit 1 UFSAR Sections 8.3.1 and 15.2.13 describe how the plant can successfully withstand and recover from the SBO event. The design basis SBO event is a four-hour event. The Unit 1 SBO analysis credits the availability of an emergency diesel generator (EDG) from PSL Unit 2 as an AAC source. Prior to one hour, the main steam safety valves cycle to control reactor coolant system (RCS) temperature and secondary pressure. At 1 hour, operator action is credited to open the atmospheric dump valves resulting in the closure of the main steam safety valves. After 4 hours, either offsite power is restored or one or both PSL Unit 1 EDGs are started, thus terminating the event.

PSL Unit 2 is licensed as a 4-hour DC coping plant, which means that it can successfully endure a complete loss of AC power for at least four hours. No credit is taken for AC power that could be supplied from the Unit 1 diesel generators. Additional details regarding the Unit 2 SBO evaluations are included in Unit 2 UFSAR Sections 8.3.1 and 15.10.

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 PSL includes the recovery path electrical equipment out to the first circuit breaker connecting to the offsite transmission system (i.e., equipment in the switchyard) consistent with the NUREG-2192 guidance. This path includes the circuit breakers that connect the switchyard to the transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between the circuit breakers and transformers, the transformers and onsite electrical distribution system and the associated control circuits and structures.

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

- The UFSARs, Technical Specifications, TRMs, licensing correspondence, SBO 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 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 PSL Unit 1 and 2 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 PSL 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 Attachments 1, 2, and 3.

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

Each PSL 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:
    - FP (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 PSL, the SR components are identified in NAMS. The SR classification in NAMS was populated using a controlled procedure that is consistent with the above 10 CFR 50.34(a)(1) criteria and design verified. The SR classification is also considered a controlled attribute in the database, and any modification to a component's safety classification must be design verified.

SR classifications for systems and structures are based on system and structure descriptions and analysis in the UFSARs. SR structures are those structures listed in the UFSARs and classified as Class I. Systems and structures identified as SR in the UFSARs meet the criteria of 10 CFR 54.4(a)(1) and are included within the scope of SLR. SR 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 PSL Units 1 and 2 CLBs, 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 NNS SSCs with respect to the following application or configuration categories:

- NNS SSCs that may have the potential to prevent satisfactory accomplishment of safety functions,
- NNS SSCs directly connected to SR SSCs that provide structural support for the SR SSCs, and
- NNS SSCs that are not directly connected to SR SSCs but have the potential to affect SR 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 NNS SSCs that are required to function in support of SLR intended functions of SR SSCs. This functional requirement distinguishes this category from other categories where the NNS SSCs are only required to maintain adequate integrity to preclude structural failure or spatial interaction.

The identification of the PSL SSCs determined to be within the scope of 10 CFR 54.4(a)(2) for original PSL license renewal is described in the original Unit 1 and Unit 2 scoping 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 PSL SLR. Additional sources of information used to determine this scope includes the original license renewal NRC Safety Evaluation Report, NUREG-1779, plant design modifications implemented between January 1, 2003 and October 1, 2020, and the information sources listed in Section 2.1.2.

<u>Nonsafety-Related SSCs Credited Design Features in the PSL Units 1 and 2 CLBs</u>

NNS 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 PSL Units 1 and 2 CLBs where this can occur include the following:

<u>Cranes</u>

Cranes are used in support of Unit operations and maintenance activities and may be used to move heavy loads over SR 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 SR function, are considered to meet the criteria of 10 CFR 54.4(a)(2) and within the scope of SLR. Additional details for the cranes included in the scope of SLR can be found in Section 2.4.18.

High-Energy Line Break (HELB)

For PSL Unit 1, the definition of high energy piping systems are systems in which operating temperatures exceed 200°F and operating pressures exceed 275 psig. Piping systems 1" nominal pipe size and smaller are excluded from HELB review.

For PSL Unit 2, the definition of high energy piping systems are described as high energy (i.e., fluid systems which exceed 200°F or 275 psig during normal operating conditions) and moderate energy (i.e., fluid systems which are 200°F or less, and 275 psig or less during normal operating conditions). High energy or moderate energy piping 1" nominal pipe size and smaller are excluded from HELB review.

NNS whip restraints, jet impingement shields, blowout panels, etc. that are designed and installed to protect SR equipment from the effects of a HELB are within the scope of SLR per 10 CFR 54.4(a)(2). Additional details for the HELB structural components included in the scope of SLR can be found in Section 2.4.

Missiles

Missiles can be generated from internal events such as failure of rotating equipment or external events. Inherent NNS features that protect SR equipment from internal and external missiles are within the scope of SLR per 10 CFR 54.4(a)(2). Additional details for the structural components that provide protection from missiles included in the scope of SLR can be found in Section 2.4.

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). NNS sump pumps, piping and valves are necessary to mitigate the effects of a flood that threatens SR 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 SR SSCs are within the scope of SLR per 10 CFR 54.4(a)(2), and are typically included as part of the building structure. Additional details for the structural components that provide flood protection included in the scope of SLR can be found in Section 2.4.

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

In some cases, SR SSCs may rely on certain NNS SSCs to perform a system function. These NNS SSCs are listed below:

- Operation of the Unit 1 and 2 NNS reactor cavity cooling systems and the reactor support cooling systems is required to maintain the air temperature in the Unit 1 and 2 reactor cavity to less than the 150ºF air temperature limit considered in the evaluation of the primary shield wall (Section 2.3.3.12).
- The NNS flow path to the PSL Unit 1 and 2 CCW surge tanks is supplied from the fire protection system. The piping that connects the fire protection system to the CCW surge tanks is included in the scope of SLR (Section 2.3.3.2).

These NNS 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, Revision 6 states that for NNS SCs that are directly connected to SR SCs (typically piping systems), the NNS piping and supports, up to and including the first equivalent anchor beyond the SR/NNS 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 NNS 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, Revision 6 apply to the identification of the first seismic or equivalent anchor at PSL:

- 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 NNS piping and associated structures and components attached to SR 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 SR/NNS piping interface is to include enough of the NNS 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 SR/NNS interface, and

(2) Ensuring NNS piping loads are not transferred through the SR/NNS interface.

The following methods (a) through (d) were used to define end points for the portion of NNS 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 NNS 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 SR 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 NNS piping, such as a drainpipe that ends at an open floor drain.

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

For SLR, PSL has included all the connected NNS 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, Revision 6. Note that these piping segments are not uniquely identified on the SLRBDs. The aging effects for directly connected NNS piping are managed using the same programs that manage the SR piping. The associated NNS 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.

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

NNS systems that are not connected to SR piping or components, or are outside the structural support boundary for the attached SR piping system, and have a spatial relationship such that their failure could adversely impact the performance of a SR 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), PSL has chosen the preventive option for SLR. The preventive option involves identifying the NNS SSCs that have a spatial relationship such that failure could adversely impact the performance of a SR SSC intended function and including the identified NNS SSC within the scope of SLR without consideration of plant mitigative features. The concern is that age-related degradation of NNS SSCs could lead to adverse interactions with SR SSCs that have not been previously considered.

During the original PSL LRA review, NRC staff issued RAI 2.1-1 (Reference ML021830228) which requested clarification of the PSL scoping criteria for 54.4(a)(2). The PSL response to the RAI was provided to the NRC in FPL letter L-2002-139 (Reference ML022700567) and it addressed all NNS SSCs that affect SR SSCs that are within the scope of license renewal as defined in 10 CFR 54.4(a)(2). Subsequent to this PSL response, the NRC issued NUREG-1779, the final SER for PSL license renewal. In Section 2.1.2.1 of the SER, the NRC stated that the staff has reviewed the FPL supplemental information and finds it to be acceptable on the basis of the FPL inclusion of additional NNS SSCs which meet the 10 CFR Part 54.4(a)(2) requirements using the revised methodology.

Each mechanical system within the scope of SLR was reviewed to confirm that NNS 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 Sections 2.3.1 through 2.3.4 and these components are shown highlighted in red on each applicable SLRBD.

2.1.4.2.4 Abandoned Equipment

In addition to NNS SSCs, the potential impact any abandoned equipment could have on SR SSCs must also be addressed. To eliminate the potential for indoor abandoned equipment to pose a leakage or spray threat to SR equipment, a commitment will be made as part of SLR to revise plant procedures to require the periodic venting and draining of indoor abandoned equipment that is directly connected to in-service systems. Abandoned equipment that remains connected to SR SSCs will be included in the scope of license renewal as applicable per the discussion above for NNS SSCs directly connected to SR SSCs. Another acceptable option is to physically disconnect abandoned equipment from in-service equipment. Abandoned equipment that is no longer directly connected to in-service systems will be verified to be vented and drained. The following commitments will be in place and fully implemented prior to entering the SPEO as detailed in commitment number 48 in the proposed PSL Units 1 and 2 UFSAR Appendices A1 and A2, respectively:

(a) Update plant procedures to require the periodic venting and draining of indoor abandoned equipment located outside containment that is directly connected to in-service systems

(b) Verify that abandoned equipment that is no longer directly connected to in-service systems is vented and drained

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).*

The scoping 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 technical reports. The intended functions define the plant process, condition, or action that must be accomplished to perform or support a safety function for responding to a design basis event (10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2)) or to perform or support a specific requirement of one 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. This screening process provides the final determination of the specific components/structures within the scope of the rule.

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. The mechanical system boundaries are depicted on the SLR boundary drawings (SLRBDs) included in each mechanical system report. The in-scope boundaries of the mechanical systems that are required to perform or support SR functions (10 CFR 54.4(a)(1)) or that are required to demonstrate compliance with one of the five license renewal regulated events (10 CFR 54.4(a)(3)) are shown highlighted in green on each applicable SLRBD. Nonsafety-related (NNS) mechanical systems that are required for functional support of equipment that is included in the scope of license renewal for 10 CFR 54.4(a)(1) are also highlighted in green on each applicable SLRBD. NNS mechanical components that are included within the scope of license renewal because their failure could prevent the accomplishment of a SR function due to potential spatial interaction are shown highlighted in red on each applicable SLRBD.

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 (Section 2.1.5.1), civil structures (Section 2.1.5.2), and electrical and I&C systems (Section 2.1.5.3).

2.1.5 Screening Methodology

This section discusses the screening process used at PSL 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 PSL 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 2.3, Section 2.4, and Section 2.5, 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 technical reports. 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 2.2-1 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/structural component screening process is performed on each 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 ventilation system screening and AMR technical report and multiple mechanical systems in the containment isolation 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 method for determining which SCs are subject to AMR include the following:

- 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.
- NNS mechanical components and piping segments beyond the SR/NNS boundaries that have the intended function of ensuring structural integrity of the attached SR components under CLB design loading conditions are in the scope of SLR per 10 CFR 54.4(a)(2).
- In addition, NNS SCs not directly connected to SR SCs whose failure could prevent the performance of a SR 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 NNS SCs could adversely impact NNS SCs through spatial interaction. These NNS SCs are highlighted in red 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 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.

As discussed in Section 2.4.1.3 of the original PSL license renewal safety evaluation report, NUREG-1779 and associated response to RAI 2.4.1-5 (Reference ML022810608), thermal insulation on mechanical components was not determined to be within the scope of license renewal because it does not perform or support any license renewal intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). This conclusion was based on the fact that the environmental temperature qualification of in-containment components is maintained through temperature monitoring and the PSL Units 1 and 2 Technical Specifications which require the Unit 1 and 2 primary containment average temperature to be less than 120º during normal operation. Thermal insulation is not credited for environmental qualification and provides a negligible heat transfer effect with regard to containment heat loads following design basis accidents. Additionally, no insulation is credited in the environmental qualification of individual electrical components (insulated boxes, etc.).

As stated in Section 6.2.2.2 of the PSL Unit 1 and 2 UFSARs, thermal insulation inside the containments has been evaluated for failure during design bases accidents and considered in the post-accident debris transport calculations for the containment sumps. In addition, during NRC scoping and screening inspections performed as part of the original PSL license renewal application review, the staff confirmed that insulation is not credited for temperature control or for environmental qualification at PSL.

However, for SLR, it has been determined that thermal insulation on Type 1 (hot) containment piping penetrations and on process piping with temperatures above 200ºF outside containment is in the scope of SLR to assist in maintaining local concrete temperatures to acceptable levels.

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 PSL 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 Structures
- 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 SR and NNS systems are identified. This includes a walkdown of each plant area containing both SR and NNS 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 OE.

2.1.5.3 Electrical and Instrumentation & Controls

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 SR equipment, and insulate electrical conductors. Structures and components may have multiple intended functions. PSL has considered multiple intended functions where applicable, consistent with the staff guidance provided in Table 2.1-3 of NUREG-2192.

Table 2.1-1 provides expanded definitions of structure and component passive intended functions identified for the PSL SLR project.

Table 2.1-1
Passive Structure/Component Intended Function

Intended Function	Definition
Absorb neutrons	Absorb neutrons.
Coating integrity	Maintain coating integrity during a design basis accident
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.).
Electrical continuity	Provide electrical connections to specified sections of an electrical circuit to deliver voltage, current or signals
Emergency cooling water source	Provide an alternate source of cooling water in case of a loss of the normal cooling water source
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 protection	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.
Heat transfer	Provide heat transfer
Insulate (electrical)	Insulate and support an electrical conductor
Insulate (thermal)	Inhibit/prevent heat transfer across a thermal gradient
Leakage boundary (spatial)	NNS components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of SR SSCs
Mechanical closure	Provide closure of components. Typically used with bolting
Missile barrier	Provide missile barrier (internally or externally generated)
Moisture removal	Remove moisture from air
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

Table 2.1-1
Passive Structure/Component Intended Function

Intended Function	Definition
Structural integrity (attached)	NNS 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 NNS components
Throttle	Provide flow restriction
Vortex prevention	Prevent vortex in pump suction lines

2.1.5.5 Stored Equipment

The PSL 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 PSL NFPA 805 NSCA represents the safe shutdown analysis (SSA). That report was reviewed and confirmed that the PSL 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. Structural sealants within the scope of SLR are identified in Section 2.4.
- 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 Interim Staff Guidance Discussion

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). These ISGs provide revisions to NUREG-2191 and NUREG-2192 sections and tables that supersede the content in the NUREGs and are intended to be used within the context of the NUREGs. As of June 30, 2021, the following ISGs have been issued:

- SLR-ISG-2021-04-ELECTRICAL, Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance, Interim Staff Guidance, February 2021 (Reference ML20181A395)

- SLR-ISG-2021-03-STRUCTURES, Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance, Interim Staff Guidance, February 2021 (Reference ML20181A381)

- SLR-ISG-2021-02-MECHANICAL, Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance, Interim Staff Guidance, February 2021 (Reference ML20181A434)

- SLR-ISG-2021-01-PWRVI, Updated Aging Management Criteria for Reactor Vessel Internal Components for Pressurized-Water Reactors, Interim Staff Guidance, January 2021 (Reference ML20217L203)

The information provided in these ISGs has been incorporated into the PSL SLRA, where applicable. 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 Guidance (SLR-ISG-2021-04-ELECTRICAL)

This SLR-ISG includes revisions to the following NUREG-2191 report sections:

- NUREG-2191 AMP XI.E3A, Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

- NUREG-2191 AMP XI.E3B, Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

- NUREG-2191 AMP XI.E3C, Electrical Insulation for Inaccessible Low Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- NUREG-2191 AMP XI.E7, High-Voltage Insulators

2.1.6.2 Updated Aging Management Criteria for Structures Portions of Subsequent License Guidance (SLR-ISG-2021-03-STRUCTURES)

This SLR-ISG includes revisions to the following NUREG-2191 and NUREG-2192 report sections:

- NUREG-2191 AMP XI.S8, Protective Coating Monitoring and Maintenance
- NUREG-2192 Section 3.5.2.2.1.5, *"Cumulative Fatigue Damage,"* SRP-SLR Section 3.5.3.2.1.5, *"Cumulative Fatigue Damage,"* SRP-SLR Section 3.5.6, "References," GALL-SLR Report Chapter II, and aging management review (AMR) items associated with cracking due to cyclic loading in SRP-SLR Table 3.5-1, *"Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report"*
- NUREG-2191 Chapter II to Allow Plant-Specific Aging Management Options
- NUREG-2191 Chapter III to Allow Plant-Specific Aging Management Options
- NUREG-2192 Section 3.5 and Table 3.5-1 to Allow Plant-Specific Aging Management Options and Provide Option to Perform Further Evaluation

2.1.6.3 Updated Aging Management Criteria for Mechanical Portions of Subsequent License Guidance (SLR-ISG-2021-02-MECHANICAL)

This SLR-ISG includes revisions to the following NUREG-2191 and NUREG-2192 report sections:

- NUREG-2191 AMP X.M2, Neutron Fluence Monitoring
- NUREG-2191 AMP XI.M2, Water Chemistry
- NUREG-2191 AMP XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)
- NUREG-2191 AMP XI.M21A, Closed Treated Water System
- Aging Management Review Line Items Associated with NUREG-2191 AMP XI.M26, Fire Protection
- NUREG-2192 Table 3.3-1 and GALL-SLR Table VII H2 to Address Reduction of Heat Transfer for Heat Exchanger Tubes in a Fuel Oil Environment

- NUREG-2192 Table 3.3-1 and GALL-SLR Table VII H2 to Address Loss of Material in Nickel Alloy Strainer Components in Fuel Oil
- NUREG-2191 AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers and Tanks

2.1.6.4 Updated Aging Management Criteria for Reactor Vessel Internal Components for Pressurized-Water Reactors (SLR-ISG-2021-01-PWRVI)

This SLR-ISG includes revisions to the following NUREG-2191 and NUREG-2192 report sections:

- NUREG-2192, Table 3.1-1
- NUREG-2191, Tables IV.B2, IV.B3 and IV.B4
- NUREG-2192 Further Evaluation items 3.1.2.2.9 and 3.1.3.2.9
- NUREG-2191 AMP XI.M16A, PWR Vessel Internals
- NUREG-2191, Table IX.C
- NUREG-2192, Table 4.7-1

2.1.7 <u>Generic Safety Issues</u>

In accordance with the guidance in NEI 17-01 and NUREG-2192, review of NRC 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. Two GSIs designated as Active, Issue 186 and Issue 193, were reviewed to assure they did not involve aging effects for structures and components subject to an AMR or TLAA evaluations.

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 PSL, 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 containment spray 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 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 PSL, 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 PSL 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 PSL 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

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	PSL System Name	In Scope for SLR Unit 1	In Scope for SLR Unit 2	Sections
Reactor Vessels, Internals, and Reactor Coolant System				
Reactor Vessels	Reactor Coolant	Y	Y	2.3.1.1
Reactor Vessel Internals		Y	Y	2.3.1.2
Pressurizers		Y	Y	2.3.1.3
Reactor Coolant and Connected Piping		Y	Y	2.3.1.4
Steam Generators		Y	Y	2.3.1.5
Engineered Safety Features				
Containment Cooling	Containment Fan Coolers	Y	Y	2.3.2.1
Containment Spray	Containment Spray	Y	Y	2.3.2.2
Containment Isolation	Integrated Leak Rate Test	Y	Y	2.3.2.3
	Service Air	Y	Y	2.3.2.3
	Containment Vacuum Relief	Y	Y	2.3.2.3
	Containment Purge	Y	Y	2.3.2.3
	Hydrogen Purge	Y	N/A	2.3.2.3
	Continuous Containment/Hydrogen Purge	N/A	Y	2.3.2.3
Safety Injection	Safety Injection	Y	Y	2.3.2.4
Containment Post-Accident Monitoring	Radiation Monitoring	Y	Y	2.3.2.5
	Hydrogen Sampling	Y	Y	2.3.2.5
	Post-Accident Sampling	N	Y	2.3.2.5
Auxiliary Systems				
Chemical and Volume Control	Chemical and Volume Control	Y	Y	2.3.3.1
Component Cooling Water	Component Cooling Water	Y	Y	2.3.3.2
Demineralized Makeup Water	Demineralized Makeup Water	Y	Y	2.3.3.3
Diesel Generators and Support Systems	Diesel Fuel Oil	Y	Y	2.3.3.4
	Diesel Generator	Y	Y	2.3.3.4
Fire Protection / Service Water	Fire Protection	Y	Y	2.3.3.5
	Service Water	Y	Y	2.3.3.5
	RCP Oil Collection	Y	Y	2.3.3.5
Fuel Pool Cooling	Fuel Pool Cooling	Y	Y	2.3.3.6
Instrument Air / Miscellaneous Bulk Gas Supply	Instrument Air	Y	Y	2.3.3.7
	Miscellaneous Bulk Gas Supply	Y	Y	2.3.3.7
Intake Cooling Water / Emergency Cooling Canal	Intake Cooling Water	Y	Y	2.3.3.8
	Emergency Cooling Canal	Y	Y	2.3.3.8
Primary Makeup Water	Demineralized Water	Y	Y	2.3.3.9

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	PSL System Name	In Scope for SLR Unit 1	In Scope for SLR Unit 2	Sections
	Primary Makeup Water	Y	Y	2.3.3.9
Sampling	Sampling	Y	Y	2.3.3.10
Turbine Cooling Water	Turbine Cooling Water	Y	N	2.3.3.11
Ventilation	Shield Building Ventilation	Y	Y	2.3.3.12
	Control Room Air Conditioning	Y	Y	2.3.3.12
	ECCS Area Ventilation	Y	Y	2.3.3.12
	RAB Main Supply & Exhaust	Y	Y	2.3.3.12
	RAB Electrical & Battery Room Ventilation	Y	Y	2.3.3.12
	Fuel Handling Building Ventilation	N	Y	2.3.3.12
	CEDM Cooling	N	N	N/A
	Reactor Cavity Cooling	Y	Y	2.3.3.12
	Reactor Support Cooling	Y	Y	2.3.3.12
	Intake Structure Ventilation	N/A	Y	2.3.3.12
	Miscellaneous Ventilation	Y	N	2.3.3.12
	Containment Airborne Radioactivity	N	N/A	N/A
	Turbine Switchgear Room Ventilation	N	N	N/A
Waste Management	Waste Management	Y	Y	2.3.3.13
	Safeguards Pump Room Drain	Y	Y	2.3.3.13
Steam and Power Conversion				
Main Steam	Main Steam	Y	Y	2.3.4.1
	Auxiliary Steam	Y	Y	2.3.4.1
	Turbine	Y	Y	2.3.4.1
Main Feedwater and Steam Generator Blowdown	Main Feedwater	Y	Y	2.3.4.2
	Heater Drains and Vents	Y	N	2.3.4.2
	Steam Generator Blowdown	Y	Y	2.3.4.2
Auxiliary Feedwater and Condensate	Auxiliary Feedwater	Y	Y	2.3.4.3
	Condensate	Y	Y	2.3.4.3
Extraction Steam	Extraction Steam	N	N	N/A
Turbine Lube Oil	Turbine Lube Oil	N	N	N/A
Condensate Polishing	Condensate Polishing	N	N	N/A
Chemical Feed	Chemical Feed	N	N	N/A
Circulating Water	Circulating Water	N	N	N/A
Miscellaneous Drains	Miscellaneous Drains	N	N	N/A
Condensate Recovery	Condensate Recovery	N	N	N/A
Processed Blowdown	Processed Blowdown	N	N	N/A
Sluice Water	Sluice Water	N	N	N/A

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	PSL System Name	In Scope for SLR Unit 1	In Scope for SLR Unit 2	Sections
Spent Resin – SGBTF	Spent Resin – SGBTF	N	N	N/A
Blowdown Cooling	Blowdown Cooling	N	N	N/A
Air Blower System	Air Blower System	N	N	N/A
Blowdown Waste Management	Blowdown Waste Management	N	N	N/A
Wet Lay-up	Wet Lay-up	N	N	N/A
Hypochlorite	Hypochlorite	N	N	N/A
Neutralization Basin	Neutralization Basin	N	N	N/A
SGBTF Demineralization	SGBTF Demineralization	N	N	N/A
SGBTF Radiation Monitoring	SGBTF Radiation Monitoring	N	N	N/A
Water Treatment Plant	Water Treatment Plant	N	N	N/A
Containments, Structures, and Component Supports				
Containment Building Structures	Containment Vessel	Y	Y	2.4.1
	Reactor Containment Building	Y	Y	
Plant Structures	Overhead Heavy Load Handling Systems	Y	Y	2.4.18
	Component Support Commodity	Y	Y	2.4.16
	Intake, Discharge, and Emergency Cooling Canals	Y	Y	2.4.8
	Intake Structures	Y	Y	2.4.9
	Switchyard	Y	Y	2.4.12
	Ultimate Heat Sink Dam (Barrier Wall)	Y	Y	2.4.14
	Emergency Diesel Generator Buildings	Y	Y	2.4.6
	Component Cooling Water Area	Y	Y	2.4.2
	Yard Structures	Y	Y	2.4.15
	Reactor Auxiliary Buildings	Y	Y	2.4.10
	Fuel Handling Building	Y	Y	2.4.7
	Turbine Buildings	Y	Y	2.4.13
	Steam Trestle Areas	Y	Y	2.4.11
	Diesel Oil Equipment Enclosures	Y	Y	2.4.5
	Condensate Polisher Building	Y	N	2.4.3
	Condensate Storage Tank Enclosures	Y	Y	2.4.4
	Fire Rated Assemblies	Y	Y	2.4.17
	Intake and Discharge Pipelines	N	N	N/A
	Intake Velocity Caps	N	N	N/A
	PSL and Hutchinson Island Substations	N	N	N/A

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	PSL System Name	In Scope for SLR Unit 1	In Scope for SLR Unit 2	Sections
	Meteorological Tower	N	N	N/A
	Steam Generator Blowdown Treatment Facility	N	N	N/A
	Sodium Hypochlorite Control Room	N	N	N/A
	South Security Building	N	N	N/A
	North Security Building	N	N	N/A
	South Service Building	N	N	N/A
	North Service Building (including maintenance shop)	N	N	N/A
	Cafeteria	N	N	N/A
	G1 & G2 Warehouses	N	N	N/A
	Unified Maintenance Facility	N	N	N/A
	Dry Storage Warehouse	N	N	N/A
	Gas House	N	N	N/A
	Fire House	N	N	N/A
	Hot Tool Room	N	N	N/A
	Water Treatment Plant	N	N	N/A
	F4 Warehouse	N	N	N/A
	Rotating Maintenance Shop	N	N	N/A
	Backfit Maintenance Shop	N	N	N/A
	Carpenter Shop	N	N	N/A
	Oil Storage Facility	N	N	N/A
	Chemical Storage Facility	N	N	N/A
	Coatings & Coatings Storage Facilities	N	N	N/A
	Valve & Welding Building	N	N	N/A
	Fleet Services Bldg. & Fuel Dispensing Facility	N	N	N/A
	NPS Lunchroom	N	N	N/A
	Welding Shop	N	N	N/A
	Other Miscellaneous Buildings	N	N	N/A
	FLEX Building	N	N	N/A
	Independent Spent Fuel Storage Installation (ISFSI)	N	N	N/A
	Low Level Waste Storage Facility	N	N	N/A
Electrical and I&C Systems				
Electrical and I&C Systems	6.9kV Electrical	Y	Y	2.5
	480V Electrical	Y	Y	2.5

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	PSL System Name	In Scope for SLR Unit 1	In Scope for SLR Unit 2	Sections
	120/208V Electrical	Y	Y	2.5
	120V Vital AC	Y	Y	2.5
	125VDC (Unit 2)	Y	Y	2.5
	4.16kV Electrical	Y	Y	2.5
	Generation and Distribution	Y	Y	2.5
	Diesel Generator	Y	Y	2.5
	Station Grounding	Y	Y	2.5
	Communications	Y	Y	2.5
	Reactor Protection	Y	Y	2.5
	Nuclear Instrumentation	Y	Y	2.5
	Control Element Drive Mechanism/Control	Y	Y	2.5
	Containment Electrical Penetrations (conductor, non-metallic, and non-pressure boundary portions)	Y	Y	2.5
	Safeguards Panels	Y	Y	2.5
	Data Acquisition Remote Terminal Unit	Y	Y	2.5
	Miscellaneous	Y	Y	2.5
	Meteorological Monitoring	N	N	N/A
	Reactor Regulating	N	N	N/A
	Computer – Process and Reactivity	N	N	N/A
	Loose Parts Monitoring	N	N	N/A
	Security	N	N	N/A
	Cathodic Protection	N	N	N/A
	Seismic Monitoring	N	N	N/A
	Meteorological Monitoring	N	N	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, then are 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 (RCS) 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 RCS for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both Units.

The RCS consists of two loops connected in parallel to the reactor vessel, with each loop containing a steam generator and two reactor coolant pumps (RCPs). The system also includes a pressurizer, 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 RCS transfers the heat generated in the core to the steam generators, where steam is produced to drive the turbine generator. Reactor coolant is circulated at the flow rate and temperature consistent with achieving the reactor core thermal-hydraulic performance. The reactor coolant also acts as a solvent for the neutron absorber used in chemical shim control, and as a neutron moderator and reflector. The RCS provides a boundary for containing the reactor 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 rotating assembly 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 RCS loops interface with various other systems, e.g., safety injection (SI), sampling, and the chemical and volume control system (CVCS).

Boundary

The RCS 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 PSL license renewal effort.

PSL Unit 1
SLR-8770-G-078 Sheet 110A
SLR-8770-G-078 Sheet 110B
SLR-8770-G-078 Sheet 111A
SLR-8770-G-078 Sheet 111B
SLR-8770-G-078 Sheet 111C
SLR-8770-G-078 Sheet 111D
SLR-8770-G-078 Sheet 120B
SLR-8770-G-078 Sheet 121A
SLR-8770-G-078 Sheet 131A
SLR-8770-G-078 Sheet 131B

PSL Unit 2
SLR-2998-G-078 Sheet 107
SLR-2998-G-078 Sheet 108
SLR-2998-G-078 Sheet 109
SLR-2998-G-078 Sheet 110
SLR-2998-G-078 Sheet 111A
SLR-2998-G-078 Sheet 111B
SLR-2998-G-078 Sheet 111C
SLR-2998-G-078 Sheet 111D
SLR-2998-G-078 Sheet 122
SLR-2998-G-078 Sheet 131
SLR-2998-G-078 Sheet 132

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Remove a sufficient amount of heat (i.e., core heat plus pump heat) to maintain the nuclear fuel within acceptable design limits:

(a) during normal plant operation

(b) during loss-of-offsite power event (this requires the ability to establish natural circulation cooling);

(c) during hot standby conditions (Mode 3) to maintain “safe shutdown”;

(d) during a steam generator tube rupture (SGTR) event to maintain subcooling margin while the RCS is being intentionally depressurized to terminate primary-to-secondary blowdown through the ruptured tube.

(2) Provide a flow path for decay heat removal:

(a) by the shutdown cooling system, during low temperature and low pressure conditions;

(b) by the safety injection system (for emergency core cooling) during accident conditions

(3) Provide a barrier to prevent the release of fission products from the reactor core to the environment

(4) Provide mechanical reactivity control (CEDMs)

(5) Provide for venting noncondensible gases and steam following postulated accidents or events

(6) Provide RCS overpressure protection

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 FP.

(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 ATWS.

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

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

UFSAR References

4.2.2, 5 (Unit 1)
3.9.5, 4.5, and 5 (Unit 2)

Components Subject to AMR

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

- Reactor Vessels (Section 2.3.1.1)
- Reactor Vessel Internals (Section 2.3.1.2)

- Pressurizers (Section 2.3.1.3)
- Reactor Coolant Piping (Section 2.3.1.4)
- Steam Generators (Section 2.3.1.5)

2.3.1.1 Reactor Vessels

Description

The PSL reactor vessels consist of cylindrical shells with hemispherical bottom heads and flanged removable upper heads. The component intended functions of the reactor vessels include pressure boundary integrity, structural support, and flow distribution.

The reactor vessel shells are fabricated from courses of multiple plates joined by axial and circumferential welds. The reactor vessels contain the cores, core support structures, control element assemblies, and other parts directly associated with the cores. Inlet and outlet nozzles are located at an elevation between the head flanges and the cores. Each removable reactor vessel upper head contains a bolting flange employing studs and nuts. Two metallic O-rings form a pressure-tight seal in concentric grooves in the head flange. The O-rings are currently replaced each time the reactor vessel upper head is removed. Therefore, the O-rings are not long-lived and do not require an aging management review in accordance with 10 CFR 54.21(a)(1)(ii).

The control element drive mechanisms (CEDMs) are attached to penetrations on the reactor vessel upper heads. In-core flux measuring instruments and heated junction thermocouples enter the upper heads through the in-core instrumentation flanges. Note that only the pressure boundary portions of the control element drive mechanisms are included in the scope of license renewal. The active portions of the control element drive mechanisms do not require an aging management review in accordance with 10 CFR 54.21(a)(1)(i).

Boundaries between the reactor vessels and associated systems and components are typically drawn at the reactor vessels interface. The evaluation boundaries for the reactor vessels extend to the primary inlet and outlet nozzle safe ends, head penetration nozzles and pressure housings, and the vent pipe out to the first bolted flange. As such, the following systems/components are not considered as part of the reactor vessels:

- Reactor coolant and connected piping. Refer to Section 2.3.1.4 for the review of these components.

- The reactor vessel support structure and service structure. Refer to Section 2.4.1 for the review of these structural components.

UFSAR References

5.4 (Unit 1)
5.3 (Unit 2)

Components Subject to AMR

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

Table 3.1.2-1 provides the results of the AMR.

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

Component Type	Component Intended Function(s)
Bottom head	Pressure boundary
CEDM motor housing lower end fitting	Pressure boundary
CEDM motor housing upper pressure housing	Pressure boundary
CEDM nozzle tubes and adapter	Pressure boundary
Closure head (mono-block forging)	Pressure boundary
Closure studs, nuts, and washers	Mechanical closure
Core stabilizing lugs	Structural support
Core stop lugs	Structural support
Flow baffles	Flow distribution
ICI nozzle adapters	Pressure boundary
ICI nozzle tubes	Pressure boundary
ICI seal carrier assemblies	Pressure boundary
Insulation support ring (Unit 1)	Structural support
Nozzle support pads	Structural support
Primary inlet/outlet nozzle safe ends	Pressure boundary
Primary inlet/outlet nozzles	Pressure boundary
Reactor vessel components with fatigue analysis	Pressure boundary
Refueling seal rings	Pressure boundary Structural support
RVLMS pressure housing (Unit 1)	Pressure boundary
RVLMS pressure housing lower end fitting (Unit 1)	Pressure boundary
RVLMS upper flange (Unit 1)	Pressure boundary
Service structure support pad (Unit 2)	Structural support
Shells (lower, intermediate, upper)	Pressure boundary
Vent pipe	Pressure boundary
Vent pipe nozzle	Pressure boundary
Vessel closure flange and studs	Mechanical closure
Vessel flange	Pressure boundary Structural support

2.3.1.2 Reactor Vessel Internals

Description

The PSL Units 1 and 2 reactor vessel internals are essentially similar, except for minor dimensional and design details or material differences. The original Unit 1 reactor vessel internals design included a thermal shield but the thermal shield was found in 1983 to be damaged and was removed without a replacement. The specific repairs that were made on the Unit 1 core support barrel in 1983 are described in detail in a letter to the NRC (L-84-29). The original Unit 2 reactor vessel internals design did not include a thermal shield. Because of the similarity between the Unit 1 and Unit 2 reactor vessel internals in materials, environment, design, shape, dimensions and function, the descriptions, and evaluations in this document address both Unit 1 and Unit 2. Where a deviation exists in sizes, numbers, or materials, both values are given. When a difference exists in shape or function, the difference is described.

The reactor vessel internals were designed to guide the reactor coolant flow within the reactor vessel to assure proper heat transfer and core cooling. The reactor vessel internals were also designed to house, support, align, and guide the fuel assemblies, the control element assemblies, and the in-core instrumentation for proper integrated functioning. The reactor vessel internals include all the structures and parts inside the reactor pressure vessel which are not welded to the reactor vessel. The fuel assemblies and the control element assemblies (CEAs) are exceptions to this as they are not considered to be long lived components and therefore do not require aging management review.

UFSAR References

4.2.2 (Unit 1)
3.9.5 and 4.5.2 (Unit 2)

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)
"No Additional Measures" components	Structural support Flow distribution
ASME Section XI, examination category B-N-3 reactor vessel internals components	Structural support
Core barrel assembly: upper flange	Structural support
Core shroud assembly: remaining axial welds	Structural support
Core shroud plate-former plate weld	Structural support
Core shroud tie rods	Structural support
Core stabilizing lugs, shims, and bolts	Structural support
Core support barrel assembly: lower axial weld	Structural support
Core support barrel assembly: lower girth weld	Structural support
Core support barrel assembly: middle axial weld	Structural support
Core support barrel assembly: middle girth weld	Structural support
Core support barrel assembly: upper flange weld	Structural support
Core support barrel assembly: upper girth weld and upper axial weld	Structural support
Core support barrel expandable plugs and patches (Unit 1)	Structural support
Core support barrel flexure weld	Structural support
Core support columns	Structural support
Core support plate	Structural support Flow distribution
Fuel alignment plate	Structural support
Guide lugs, guide lug inserts, and bolts	Structural support
Lower core support beams	Structural support
Lower support structure: fuel alignment pins	Structural support
Peripheral instrument guide tubes	Structural support
Reactor vessel internal components	Structural support Flow distribution
Reactor vessel internal components with a fatigue analysis	Structural support Flow distribution
Remaining instrument guide tubes	Structural support
Welded core shroud assembly	Structural support Flow distribution

2.3.1.3 Pressurizers

Description

The pressurizers are vertical cylindrical vessels containing electric heaters in the lower heads, water spray nozzles in the upper heads, nozzles, safe ends, manway covers, and integral support structure. The component intended functions of the pressurizers include pressure boundary integrity, insulate (thermal), and structural support.

Since piping with no intervening isolation valves interconnects sources of heat in the reactor coolant system, overpressure protection for the reactor coolant system is provided by the pressurizers. Overpressure protection consists of three spring-loaded ASME Code safety valves and two power-operated relief valves on each pressurizer.

Boundaries between the pressurizers and associated systems and components are typically drawn at the pressurizers interface, after the nozzle safe ends or flanges, as applicable. As such, the following systems/components are not considered as part of the pressurizers:

- Reactor coolant and connected piping. Refer to Section 2.3.1.4 for the review of these components.
- The pressurizer support skirt flange anchor bolts. Refer to Section 2.4.1 for the review of these structural components.

UFSAR References

5.5.2 (Unit 1)
5.4.10 (Unit 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 3.1.2-3 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)
Alloy 600 small bore nozzle repairs (Unit 2)	Pressure boundary
Heater sheath and thermowell	Pressure boundary
Heater sleeves	Pressure boundary
Instrument nozzle	Pressure boundary
Lower head	Pressure boundary
Manway cover	Pressure boundary
Manway cover bolting	Mechanical closure
Pressurizer components subject to fatigue	Pressure boundary
Safety valve flanges	Pressure boundary
Shell	Pressure boundary
Spray nozzle, surge nozzle, relief valve nozzle, safety valve nozzle	Pressure boundary
Steel components	Pressure boundary Structural support
Support skirt and flange	Structural support
Surge nozzle and relief valve nozzle structural weld overlay (Unit 2)	Pressure boundary
Surge nozzle safe ends, spray nozzle safe ends, relief nozzle safe ends	Pressure boundary
Thermal sleeve (spray nozzle, surge nozzle) (Unit 1)[2]	Insulate (thermal)
Upper head	Pressure boundary

Notes:

1. In accordance with Section 2.3.1.2.2 of NUREG-1779, 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 NUREG-1779. 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 pressurizer pressure boundary. The Unit 1 thermal sleeves provide thermal shielding to minimize nozzle low-cycle thermal fatigue. The Unit 2 thermal sleeves were demonstrated through analysis to not be relied on to limit fatigue as documented in the FPL response to Open Item 3.1.2.2-1 (Reference ML031550376) and are not credited with limiting fatigue in TLAA Section 4.3.1. As such, the Unit 2 thermal sleeves do not have a license renewal intended function.

2.3.1.4 Reactor Coolant Piping

Description

Reactor coolant piping consists of piping (including fittings, branch connections, flow restrictors, and thermowells), pressure retaining parts of valves, pressure boundary components of the RCPs, and bolted closures and connections. Reactor coolant piping is presented in two parts:

- Class 1 piping
- Non-Class 1 piping

Class 1 Piping

Class 1 piping includes the main coolant piping and pressure boundary components of the RCPs; pressurizer surge, spray, safety, and relief lines; vents, drains, instrumentation lines, and orifices; and Class 1 portions of ancillary systems attached to the RCS. Ancillary systems attached to the RCS include SI, primary sampling, and CVCS.

Non-Class 1 Piping

Several non-Class 1 reactor coolant components are within the scope of SLR. These non-Class 1 reactor coolant components are piping and piping components connecting to instrumentation and generally does not interact with other in scope systems and the system boundary is terminated at a Class B to D break. Exceptions to this include where non-Class 1 piping interacts with the plant sampling system which maintains the Class B classification.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed in Section 2.3.1. There are no significant differences between these boundaries and the boundaries identified as part of the original PSL license renewal effort.

The reactor coolant system encompasses all of the Class 1 piping at PSL. Where the Class 1 boundary terminates within another system, all of the Class 1 components from that system are screened into the reactor coolant system and the subsequent license renewal system boundary is drawn at the class break. For non-Class 1 screening the piping is either only interacting with the Class 1 piping or is terminated at a Class B to D break. The exceptions to this are when non-Class 1 components interact with the sampling system which is detailed for each Unit below.

The Unit 1 non-Class 1 piping interacts with the sampling system at valve V1211 on SLR-8770-G-078 Sheet 110B. The Unit 1 non-Class 1 piping also interacts with the sampling system at valves V1210 and V1238 on SLR-8770-G-078 Sheet 110A.

The Unit 2 non-Class 1 piping interacts with the sampling system at valves V1238, V1210, and V1213 on SLR-2998-G-078 Sheets 108, 109, and 110, respectively.

UFSAR References

5.1, 5.2, 5.3, 5.5, and 5.6 (Unit 1)
5.1, 5.2, and 5.4 (Unit 2)

Components Subject to AMR

Table 2.3.1-4 lists the reactor coolant 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 Piping Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Alloy 600 small bore nozzle repairs	Pressure boundary
Bolting	Mechanical closure
Dissimilar metal welds	Pressure boundary
Flexible hoses	Pressure boundary
Flow element	Pressure boundary Throttle
Nozzle	Pressure boundary
Orifice	Pressure boundary Throttle
Piping[1]	Pressure boundary Structural integrity (attached)
Piping (pressurizer surge line)	Pressure boundary
Piping < 4 inches[1]	Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pump casing and cover	Pressure boundary
RCP lower seal heat exchanger tubes	Pressure boundary
Steel components	Pressure boundary
Structural weld overlay repairs	Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

Note:

1. Consistent with the NUREG-2191 definition for piping components, these components include the safe ends connected to the reactor coolant piping.

2.3.1.5 Steam Generators

Description

There are two steam generators installed in each PSL unit, one in each reactor coolant loop. Each steam generator is a vertical shell and tube heat exchanger, where heat transferred from a single-phase fluid at high temperature and pressure (the reactor coolant) through the steam generator inverted U-tubes is used to generate a two-phase (steam-water) mixture at a lower temperature and pressure on the secondary side. The reactor coolant coming from the reactor vessel enters the steam generator through a single hot leg nozzle into the primary channel head, flows through the inverted U-tubes, and exits through two cold leg nozzles in the primary channel head to the RCPs. The primary channel head is divided into inlet and outlet chambers by a vertical divider plate. The Unit 1 steam generators differ from the Unit 2 design in that they include a “stay cylinder” which provides support to the tubesheet. The steam-water mixture, generated in the secondary side, flows upward through the moisture separators to the steam outlet nozzle at the top of the vessel, providing essentially dry and saturated steam to the main steam turbine.

Manways are provided to permit access to both sides of the steam generator primary heads and to the moisture separating equipment on the secondary side of the steam generators. The secondary side of the steam generators also contains the secondary-side tube supports, tube bundle wrapper, feedwater nozzle and feedring, and moisture separation equipment.

The PSL Unit 1 steam generators were replaced in December of 1997 with Babcock and Wilcox International (BWI) replacement steam generators (RSGs) of the same form, fit and function. While the replacement was largely like for like, corrosion resistant materials and Alloy 690 U-tubes were incorporated in the design.

In fall of 2007, the Unit 2 steam generators were replaced with Areva RSGs due to primary water stress corrosion cracking and outside diameter stress corrosion cracking of the original steam generator Alloy 600 U-tubes. The Unit 2 RSGs include Alloy 690 U-tubes and other corrosion resistant materials.

Primary loop piping attached to the steam generators is Class 1 and is addressed in Section 2.3.1.4. Feedwater piping attached to the steam generators is addressed in Section 2.3.4.2. Main steam piping attached to the steam generators is addressed in Section 2.3.4.1. The primary structural supports for the steam generators are addressed in Section 2.4.1.

UFSAR References

5.5.1 (Unit 1)
5.4.2 (Unit 2)

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 3.1.2-5 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)
Blowdown nozzles	Pressure boundary
Bolting	Mechanical closure
Conical skirt	Structural support
Divider plates	Flow distribution
Feedwater feedring	Structural integrity (attached) Direct flow
Feedwater j-nozzle	Structural integrity (attached) Direct flow
Feedwater nozzle	Pressure boundary
Moisture separators	Structural integrity (attached)
Primary heads	Pressure boundary
Primary inlet and outlet nozzles	Pressure boundary
Primary instrument nozzles	Pressure boundary
Primary manway covers	Pressure boundary
Recirculation nozzles and end caps (Unit 2)	Pressure boundary
Secondary instrument nozzles	Pressure boundary
Secondary manway and handhole closure covers	Pressure boundary
Stay cylinders (Unit 1)	Pressure boundary
Steam generator components with fatigue analysis	Pressure boundary
Steam generator components: external surfaces	Pressure boundary Mechanical closure
Steam outlet nozzle (Unit 2)	Pressure boundary
Steam outlet nozzle venturis (Unit 2)	Throttle
Steam outlet nozzle with integral flow orifices (Unit 1)	Pressure boundary Throttle
Tube bundle wrapper and wrapper supports	Structural support Direct flow
Tube plugs	Pressure boundary
Tube stabilizers (stakes) (Unit 2)	Structural support
Tube support lattice bars (Unit 1)	Structural support
Tube support plates and anti-vibration bars (Unit 2)	Structural support
Tubesheets	Pressure boundary
Upper and lower shells, secondary head, transition cone	Pressure boundary
Upper vessel clevises and shear keys	Structural support
U-tubes	Pressure boundary Heat transfer

2.3.2 Engineered Safety Features

2.3.2.1 Containment Cooling

Description

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

Containment cooling is designed to remove sufficient heat to maintain the containment below its structural design pressure and temperature limits following a design basis event. In addition, the containment fan cooling units continue to operate after a design basis event to remove heat and to reduce the pressure in containment to atmospheric. Heat removed from the containment is transferred to component cooling water. Component cooling water is screened in Section 2.3.3.2. Containment cooling consists of four fan cooling units that are located outside the secondary shield wall inside each containment.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. 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 PSL license renewal effort.

PSL Unit 1:
SLR-8770-G-083 Sheet 1A
SLR-8770-G-878 Sheet 1

PSL Unit 2:
SLR-2998-G-083 Sheet 1
SLR-2998-G-878 Sheet 1

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Removes heat from containment during design basis events.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) None.

FP, 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 FP and EQ Program.

UFSAR References

6.2, 6.3 and 9.3.5 (Unit 1)
6.2, 6.5.2.2.1 and 5.4.7 (Unit 2)

Components Subject to AMR

Table 2.3.2-1 lists the containment cooling 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
Containment Cooling System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Damper housing	Pressure boundary
Drip pan	Direct flow
Duct	Pressure boundary
Flex connection	Pressure boundary
Heat exchanger (Unit 1 containment fan cooler)	Heat transfer Pressure boundary
Heat exchanger (Unit 1 containment fan motor cooler)	Heat transfer Pressure boundary
Heat exchanger (Unit 2 containment fan cooler)	Heat transfer Pressure boundary
Steel components	Pressure boundary
Thermowell	Pressure boundary
Valve body (Unit 1 only)	Pressure boundary

2.3.2.2 Containment Spray

Description

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

Containment spray is designed to remove sufficient heat to maintain the containments below their design pressure and temperature limits following design basis events.

Containment spray for each Unit consists of two containment spray pumps that take suction from the refueling water tanks (RWTs) and spray borated water from nozzles located near the top of each containment structure. When RWT inventory is exhausted, containment spray pump suction is switched to the containment recirculation sumps and the shutdown cooling heat exchangers are used to remove heat from the recirculated water. The shutdown cooling heat exchangers are screened with safety injection in Section 2.3.2.4. The containment spray system now includes sump strainers which have been added since original license renewal. These sump strainers replaced the sump screens that previously existed and are now treated as mechanical components rather than civil components.

Chemicals are injected into the containment spray pump suction lines during containment spray operations to control pH and for iodine absorption. Unit 1 has a sodium hydroxide tank that supplies sodium hydroxide through eductors to the suction lines of the containment spray pumps. Unit 2 has hydrazine pumps that inject hydrazine from a hydrazine storage tank into the suction lines of the containment spray pumps. In addition, Unit 2 utilizes solid trisodium phosphate (TSP) in stainless steel mesh baskets located in the vicinity of the containment recirculation sumps to control post-accident pH. The stainless steel mesh baskets are screened with civil/structural components in Section 2.4.1.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed below. Significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort are as follows:

- Containment sump strainers have been installed to meet requirements associated with Generic Safety Issue 191.
- A vortex breaker has been added in the Unit 2 RWT at the suction line to the containment spray pumps.
- Boundary drawings SLR-8770-G-078 Sheet 105A and SLR-2998-G-078 Sheet 105A now show the modified Unit 1 and new Unit 2 containment spray pump coolers. The Unit 2 containment spray pump coolers were not included as part of original license renewal.

The Unit 1 CS system interfaces with the SI system at valves V07120, V07119, V07130, V07132, V07145, and V07142 on SLR-8770-G-088 Sheet 1 and valves V07172, V07174, V07164, V07157, V07161, and V07158 on SLR-8770-G-088 Sheet 2. The Unit 1 CS system also interfaces with the SI system at several pipe segments and valves on SLR-8770-G-078 Sheet 130A and SLR-8770-G-078 Sheet 130B.

The Unit 1 CS system interfaces with the fuel pool cooling system at valve V07104 on SLR-8770-G-088 Sheet 1 and valves V07206 and V07170 on SLR-8770-G-088 Sheet 2.

The Unit 1 CS system interfaces with the ventilation system at the connection to PDIS-25-2A, PDIS-25-11A, PDIS-25-2B, and PDIS-25-11B on SLR-8770-G-088 Sheet 2.

The Unit 1 CS system interfaces with the chemical and volume control system at valves V07102 and V07103 on SLR-8770-G-088 Sheet 1.

The Unit 1 bulk gas supply system provides nitrogen cover gas to the NaOH tank as shown on SLR-8770-G-088 Sheet 1.

The Unit 2 CS system interfaces with the SI system at valves V07130, V07226, V07145, and V07222 on SLR-2998-G-088 Sheet 1 and valves V07172, V07174, V07157, V07158, MV-07-3, and MV-07-4 on SLR-2998-G-088 Sheet 2. The Unit 2 CS system also interfaces with the SI system at several pipe segments and valves on SLR-2998-G-078 Sheet 130B.

The Unit 2 CS system interfaces with the fuel pool cooling system at valve V07104 on SLR-2998-G-088 Sheet 1 and valves V07419 and V07427 on SLR-2998-G-088 Sheet 2.

The Unit 2 CS system interfaces with the ventilation system at the connection to PDIS-25-2A and PDIS-25-2B on SLR-2998-G-088 Sheet 2.

The Unit 2 CS system interfaces with the chemical and volume control system at valves V07102 and V07103 on SLR-2998-G-088 Sheet 1.

The Unit 2 CS system interfaces with the primary makeup water system at valve V07159 on SLR-2998-G-088 Sheet 1.

The Unit 2 bulk gas supply system provides nitrogen cover gas to the hydrazine tank as shown on SLR-2998-G-088 Sheet 1.

<u>PSL Unit 1:</u>
SLR-8770-G-088 Sheet 1
SLR-8770-G-088 Sheet 2
SLR-8770-G-078 Sheet 105A
SLR-8770-G-078 Sheet 130A
SLR-8770-G-078 Sheet 130B

<u>PSL Unit 2:</u>
SLR-2998-G-088 Sheet 1
SLR-2998-G-088 Sheet 2
SLR-2998-G-078 Sheet 105A
SLR-2998-G-078 Sheet 130B

<u>PSL Common:</u>
None

<u>System Intended Functions</u>

SR functions (10 CFR 54.4(a)(1)):

(1) Maintains containment temperature and pressure within design limits following a design basis event.

(2) Circulates water from the containment sump through the shutdown cooling heat exchangers to support containment cooling and emergency core cooling.

(3) Removes airborne fission products from the containment atmosphere, provides a barrier to limit leakage of radioactive fluids to the environment during recirculation and provides long term pH control following a LOCA.

(4) Supports the high pressure safety injection system to provide reactivity control during certain design basis events.

(5) Provides containment isolation.

(6) Provides refueling pressure boundary isolation.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 FP, the EQ Program, and SBO (Unit 2 only).

UFSAR References

6.2.2 (Unit 1)
6.2.2 (Unit 2)

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 (Unit 1 only)	Pressure boundary
Heat exchanger (Unit 1 containment spray pump cooler)	Heat transfer Pressure boundary
Heat exchanger (Unit 2 containment spray pump cooler)	Heat transfer Pressure boundary
Nozzle	Pressure boundary Spray
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing (containment spray)	Pressure boundary
Pump casing (Unit 2 hydrazine)	Pressure boundary
Rupture disk	Pressure boundary
Sight glass (Unit 1 only)	Pressure boundary
Steel components	Pressure boundary
Strainer	Filter Pressure boundary
Tank (Unit 1 NaOH storage)	Pressure boundary
Tank (Unit 1 refueling water)	Pressure boundary
Tank (Unit 2 hydrazine storage)	Pressure boundary
Tank (Unit 2 refueling water)	Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary
Vortex breaker	Vortex prevention

2.3.2.3 Containment Isolation

Description

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

Containment isolation is an engineered safety feature that provides for the closure or integrity of containment penetrations to prevent leakage of uncontrolled or unmonitored radioactive materials to the environment.

Containment isolation includes the containment purge, hydrogen purge (Unit 1 only), continuous containment/hydrogen purge (Unit 2 only), integrated leak rate test, and service air systems which are process systems whose only license renewal system intended function is containment isolation. Containment vacuum relief is included in this screening section even though it performs a function in addition to the containment isolation function. The additional function is to protect the containment vessels from sub atmospheric internal pressure conditions created by a containment overcooling event.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. 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 PSL license renewal effort.

PSL Unit 1:
SLR-8770-G-085 Sheet 1A
SLR-8770-G-088 Sheet 2
SLR-8770-G-091 Sheet 1
SLR-8770-G-878 Sheet 1

PSL Unit 2:
SLR-2998-G-085 Sheet 1
SLR-2998-G-088 Sheet 2
SLR-2998-G-091 Sheet 1
SLR-2998-G-878 Sheet 1
SLR-2998-G-879 Sheet 3

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Maintains containment integrity.

(2) Protects containment from excessive external pressure.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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

6.1.6, 6.2, and 9.3.1 (Unit 1)
6.2, 9.3.1, 9.4 (Unit 2)

Components Subject to AMR

Table 2.3.2-3 lists the containment isolation 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
Containment Isolation System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Debris screen	Filter
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Steel components	Pressure boundary
Valve body	Pressure boundary

2.3.2.4 Safety Injection

Description

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

Safety injection, which includes the safety injection tanks, provides emergency core cooling and reactivity control during and following design basis events. Portions of safety injection are also used for shutdown cooling functions. In addition, some portions of safety injection, including the shutdown cooling heat exchangers, are used in conjunction with containment spray to cool the containment.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. 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 PSL license renewal effort.

The Unit 1 safety injection system interfaces with the containment spray system at valves V07119, V07120, V07130, V07132, V07145, and V07142 on SLR-8770-G-088 Sheet 1 and valves V07172, V07174, V07164, V07157, V07161, and V07158 on SLR-8770-G-088 Sheet 2. The Unit 1 safety injection system also interfaces with the containment spray system at several pipe segments and valves on SLR-8770-G-078 Sheet 130A, SLR-8770-G-078 Sheet 130B, and SLR-8770-G-088 Sheet 1.

Unit 1 safety injection system interfaces with the chemical and volume control system between valves V02000 and V02360 on SLR-8770-G-078 Sheet 120A, at valve V2340 on SLR-8770-G-078 Sheet 120B, and at valve V02203 on SLR-8770-G-078 Sheet 121A.

The Unit 2 safety injection system interfaces with the containment spray system at valves V07130, V07226, V07145, V07222, and V07271 on SLR-2998-G-088 Sheet 1 and valves V07172, V07174, V07157, V07158, MV-07-3, and MV-07-4 on SLR-2998-G-088 Sheet 2. The Unit 2 safety injection system also interfaces with the containment spray system at several pipe segments and valves on SLR-2998-G-078 Sheet 130B and SLR-2998-G-088 SH1.

Unit 2 safety injection system also interfaces with the reactor coolant system at several pipe segments and valves on SLR-2998-G-078 Sheet 120 and at valve V2440 on SLR-2998-G-078 Sheet 122.

<u>PSL Unit 1:</u>
SLR-8770-G-078 Sheet 105A
SLR-8770-G-078 Sheet 120A
SLR-8770-G-078 Sheet 120B
SLR-8770-G-078 Sheet 121A
SLR-8770-G-078 Sheet 130A
SLR-8770-G-078 Sheet 130B
SLR-8770-G-078 Sheet 131A
SLR-8770-G-078 Sheet 131B
SLR-8770-G-083 Sheet 1A
SLR-8770-G-088 Sheet 1
SLR-8770-G-088 Sheet 2

<u>PSL Unit 2:</u>
SLR-2998-G-078 Sheet 105A
SLR-2998-G-078 Sheet 120
SLR-2998-G-078 Sheet 122
SLR-2998-G-078 Sheet 130A
SLR-2998-G-078 Sheet 130B
SLR-2998-G-078 Sheet 131
SLR-2998-G-078 Sheet 132
SLR-2998-G-083 Sheet 1
SLR-2998-G-088 Sheet 1
SLR-2998-G-088 Sheet 2

<u>PSL Common:</u>
None

<u>System Intended Functions</u>

SR functions (10 CFR 54.4(a)(1)):

(1) Removes heat from the reactor core and containment during design basis events.

(2) Maintain reactor coolant system pressure boundary integrity.

(3) Provides containment isolation.

(4) Controls reactivity during certain steam line break events.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 FP and EQ Program.

(2) Perform a function that demonstrates compliance with the Commission's regulations for SBO (Unit 2 only).

UFSAR References

6.3 and 9.3.5 (Unit 1)
6.3 and 5.4.7 (Unit 2)

Components Subject to AMR

Table 2.3.2-4 lists the safety injection 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
Safety Injection System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Heat exchanger (high pressure safety injection pump cooler)	Heat transfer Pressure boundary
Heat exchanger (shutdown cooling)	Heat transfer Pressure boundary
Heat exchanger (Unit 1 low pressure safety injection pump cooler)	Heat transfer Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pump casing (high pressure safety injection)	Pressure boundary
Pump casing (low pressure safety injection)	Pressure boundary
Steel components	Pressure boundary
Tank (safety injection)	Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

2.3.2.5 Containment Post-Accident Monitoring

Description

The containment post-accident monitoring systems for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units.

The containment post-accident monitoring system includes the following subsystems:

- Containment Hydrogen Monitoring
- Containment Atmosphere Radiation Monitoring

Containment hydrogen monitoring provides indication of the hydrogen gas concentration in the containment atmosphere following a loss-of-coolant accident. The mechanical portions of containment hydrogen monitoring provide a flow path from the containment to the hydrogen analyzers and then back to the containment.

Containment atmosphere radiation monitoring measures radioactivity in the containment air. The mechanical portions of containment atmosphere radiation monitoring provide a flow path from the containment to the monitors and then back to the containment.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed below. The only significant difference between these boundaries and the boundaries identified as part of the original PSL license renewal effort is in regard to the post-accident sampling system. Portions of the post-accident sampling system were included in the original application for Unit 2. However, according to Technical Specification Amendment No. 114, the requirements to have and maintain the post-accident sampling system have been eliminated. Therefore, the post-accident sampling system is not included in the scope of license renewal except for the small portion of piping that connects to the hydrogen sampling system shown on boundary drawing SLR-2998-G-092 Sheet 1.

The Unit 1 containment post-accident monitoring system interfaces with the bulk gas system near valves V29383 and V29381 along with the hydrogen sampling and analyzer cubicles A and B on SLR-8770-G-092 Sheet 1.

The Unit 2 containment post-accident monitoring system interfaces with the bulk gas system at hydrogen sampling and analyzer cubicles 2A and 2B on SLR-2998-G-092 Sheet 1.

The Unit 2 containment post-accident monitoring system interfaces with the sampling system between valves V27110 and FSE-27-15 and between V27107 and FSE-27-16 on SLR-2998-G-092 Sheet 1.

PSL Unit 1:
SLR-8770-G-092 Sheet 1

PSL Unit 2:
SLR-2998-G-092 Sheet 1

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides containment integrity.

(2) Monitors containment radioactivity levels during any abnormal events.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 FP (Unit 2 only), SBO (Unit 2 only) and EQ Program.

UFSAR References

6.2.5.2.3 and 12.2.4.1 (Unit 1)
6.2.5.2.1, 9.3.6, and 12.3.4.2.3.1 (Unit 2)

Components Subject to AMR

Table 2.3.2-5 lists the containment post-accident monitoring system component types that require AMR and their associated component intended functions.

Table 3.2.2-5 provides the results of the AMR.

Table 2.3.2-5
Containment Post-Accident Monitoring System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Flexible hose	Pressure boundary
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Sample vessel (Unit 1 only)	Pressure boundary
Steel components	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 systems (CVCS) for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units.

The CVCS provides a continuous feed and bleed for the reactor coolant system to maintain proper water volume and to adjust boron concentration. CVCS consists of a charging subsystem, a letdown subsystem, and a boric acid makeup subsystem.

Insulation is not within the scope of license renewal for CVCS because the system does not contain boric acid solutions at concentrations that require heat tracing, tank heaters, and/or insulation to prevent precipitation.

There are Class 1 pressure boundary components that carry a CVCS equipment designation. These components are addressed with the Reactor Coolant Piping (Section 2.3.1.4).

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on P&IDs and component system designations. Significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort are shown below. These changes did not result in additions or removals of unique component/ material/ environment combinations.

A zinc (Zn) injection system was installed in both Units.

The RCP seal injection piping was removed for both Units.

A bubbler level system was installed on the Unit 2 BAM Tanks.

A gas accumulation system was added on the Unit 2 charging system.

A bypass line was installed for the Unit 1 purification filters.

The Unit 1 CVCS interfaces with the SI system at valves V02000 and V02360 on SLR-8770-G-078 Sheet 120A.

The Unit 1 CVCS interfaces with the sampling system at valves V2353, V2420, V2396, V2366 on SLR-8770-G-078 Sheet 120A.

The Unit 1 CVCS interfaces with the SI system at valve V2340 on SLR-8770-G-078 Sheet 120B.

The Unit 1 CVCS interfaces with the waste management system at valves V2315, V2317, V2329, V2318, V2320, V2332, V2321, V2323, V2335 on SLR-8770-G-078 Sheet 120B.

The Unit 1 CVCS interfaces with the reactor coolant system at valves V2431, V2432, V2433 on SLR-8770-G-078 Sheet 120B.

The Unit 1 CVCS interfaces with the SI system at valve V02203 on SLR-8770-G-078 Sheet 121A.

The Unit 1 CVCS interfaces with the reactor coolant system at valves V2199, V2301, V2302, V2103, V2104 on SLR-8770-G-078 Sheet 121A.

The Unit 1 CVCS interfaces with the SI system at valves V03000 and V03001 on SLR-8770-G-078 Sheet 131A.

The Unit 1 CVCS interfaces with the CS system at valves V07102 and V07103 on SLR-8770-G-088 Sheet 1

The Unit 1 CVCS interfaces with the IA system at valves V2126 and V2136 on SLR-8770-G-078 Sheet 121B

The Unit 2 CVCS interfaces with the SI system at valves V02013 and V02000 on SLR-2998-G-078 Sheet 120.

The Unit 2 CVCS interfaces with the sampling system at valves V2353, V2420, V2396, V2366 on SLR-2998-G-078 Sheet 120.

The Unit 2 CVCS interfaces with the reactor coolant system at valves V2199, V2301, V2302, V2303, V2304 on SLR-2998-G-078 Sheet 121A.

The Unit 2 CVCS interfaces with the waste management system at valve V2311 on SLR-2998-G-078 Sheet 121A.

The Unit 2 CVCS interfaces with the primary water system at valve V2119 on SLR-2998-G-078 Sheet 121B.

The Unit 2 CVCS interfaces with the SI system at valve V2440 on SLR-2998-G-078 Sheet 122.

The Unit 2 CVCS interfaces with the waste management system at valves V2588, V2329, V2318, V2660, V2321, V2335 on SLR-2998-G-078 Sheet 122.

The Unit 2 CVCS interfaces with the reactor coolant system at valves V2483, V2484, V2433 on SLR-2998-G-078 Sheet 122.

The Unit 2 CVCS interfaces with the SI system at valve V3101 on SLR-2998-G-078 Sheet 130B.

The Unit 2 CVCS interfaces with the IA system at valves V02051, V02054, V02055 and V02058 on SLR-2998-G-078 Sheet 121B.

PSL Unit 1:
SLR-8770-G-078 Sheet 105C
SLR-8770-G-078 Sheet 120A
SLR-8770-G-078 Sheet 120B

SLR-8770-G-078 Sheet 121A
SLR-8770-G-078 Sheet 121B
SLR-8770-G-078 Sheet 131A
SLR-8770-G-078 Sheet 150
SLR-8770-G-088 Sheet 1

PSL Unit 2:
SLR-2998-G-078 Sheet 105B
SLR-2998-G-078 Sheet 105C
SLR-2998-G-078 Sheet 120
SLR-2998-G-078 Sheet 121A
SLR-2998-G-078 Sheet 121B
SLR-2998-G-078 Sheet 122
SLR-2998-G-078 Sheet 130B
SLR-2998-G-078 Sheet 150
SLR-2998-G-088 Sheet 1

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provide high pressure source of reactor coolant makeup.

(2) Maintain reactor coolant system pressure boundary integrity.

(3) Provide containment isolation.

(4) Control core reactivity.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 FP, EQ Program, and SBO.

UFSAR References

9.3.4 (Unit 1)
9.3.4 (Unit 2)

Components Subject to AMR

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

Table 3.3.2-1 provides the results of the AMR.

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

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Heat exchanger (Letdown)[1]	Pressure boundary
Heat exchanger (Regenerative)[1]	Pressure boundary
Housing (charging pump strainers, suction stabilizers, pulsation dampers, purification filters, letdown strainers, boric acid suction strainers and ion exchangers)	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pump casing (Boric Acid Makeup)	Pressure boundary
Pump casing (Charging)	Pressure boundary
Steel components	Leakage boundary (spatial) Pressure boundary
Strainer	Filter Pressure boundary
Tank (Boric Acid Makeup)	Pressure boundary
Tank (Volume Control)	Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

Note:

1. In accordance with Section 2.3.3.1.1 of NUREG-1779, the CVCS 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 (CCW) systems for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units.

The CCW system is a closed loop cooling water system that utilizes demineralized water and a corrosion inhibitor to cool various components. The CCW system consists of two heat exchangers, three pumps, one surge tank, a chemical addition tank, and associated piping, valves, and instrumentation. The component cooling water system has two redundant essential supply header systems (designated A and B) each with a pump and heat exchanger and the capability to supply the minimum safety feature requirements during plant shutdown or LOCA conditions. The nonessential supply header (designated N), which is connected to both essential headers during normal operation is automatically isolated from both by valve closure on a safety injection actuation signal (SIAS).

The following heat exchangers are cooled by the CCW system but the screening and aging management review for these heat exchangers are performed in the systems shown in the table below.

Component	System	Section
High pressure safety injection (HPSI) pump coolers	Safety Injection	2.3.2.4
Shutdown heat exchangers	Safety Injection	2.3.2.4
Low pressure safety injection pump coolers (Unit 1 only)	Safety Injection	2.3.2.4
Containment fan coolers	Containment Cooling	2.3.2.1
Containment fan motor cooler (Unit 1 only)	Containment Cooling	2.3.2.1
Containment spray pump coolers	Containment Spray	2.3.2.2
Control room air conditioning system (Unit 2 only)	Ventilation	2.3.3.12
Fuel pool heat exchangers (Unit 2 only)	Fuel Pool Cooling	2.3.3.6
Letdown heat exchangers	Chemical and Volume Control	2.3.3.1

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed below. Significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort are as follows:

- The Unit 2 control room air conditioning Units were replaced. The new configuration is reflected on the boundary drawings.

- The fire protection lines that connect to the Unit 1 and Unit 2 surge tanks are now within the scope of SLR for the function of emergency makeup to the CCW surge tanks. Valves V15500 (Unit 1) and V15536 (Unit 2) would be manually opened for this configuration while the Unit 1 and Unit 2 valves V14100 would be closed to isolate the demineralized water system.

- The Unit 2 containment spray pump coolers were added to drawing SLR-2998-G-083 Sheet 1.

PSL Unit 1:
SLR-8770-G-083 Sheet 1A
SLR-8770-G-083 Sheet 1B
SLR-8770-G-083 Sheet 2

PSL Unit 2:
SLR-2998-G-083 Sheet 1
SLR-2998-G-083 Sheet 2

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides adequate cooling for SR components associated with containment and reactor decay heat removal during accident conditions.

(2) Provides control room cooling during accident conditions (Unit 2 only).

(3) Provides cooling for spent fuel pool heat exchangers (Unit 2 only).

(4) Provides containment isolation.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 FP and the EQ Program.

UFSAR References

9.2.2 (Unit 1)

9.2.2 (Unit 2)

Components Subject to AMR

Table 2.3.2-2 lists the CCW system component types that require 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
Heat exchanger (CCW)	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
Sight glass	Pressure boundary
Steel components	Leakage boundary (spatial) Pressure boundary
Strainer	Filter Pressure boundary
Tank (component cooling water surge)	Pressure boundary
Thermowell	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.3 Demineralized Makeup Water

Description

The demineralized makeup water (DW) systems for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units.

The DW system for Units 1 and 2 provides makeup water from the demineralized water storage tank (DWST) to various systems throughout the plant for both units. The only portions of the DW system that are in scope are due to the potential for leakage onto safety-related components.

For both units, the DW system provides makeup water to the component cooling water surge tank, diesel generator cooling water makeup tank, condensate recovery tank, radiochemistry laboratory, turbine cooling water system surge tank, steam generator blowdown system surge tank, sample room sink, and the instrument calibration shop. Portions of the Unit 2 DW system which enter into and are routed in the diesel generator building and the auxiliary building switchgear area are seismically analyzed to preclude their failure during a seismic event and are in scope due to their location.

A complete list of DW component types requiring an aging management review and the component intended functions are provided in Table 2.3.3-3. The aging management review for demineralized makeup water is discussed in Section 3.3.2.1.3.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed below. There were no changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort.

The Unit 1 system boundaries on SLR-8770-G-084 Sheet 1B are on components between coordinates E-6 and F-6. In addition, on this drawing, the components included in the scope are between components at coordinate G-4 and valve V38115 down through the Unit 1 diesel generator building continuations to SLR-8770-G-096 Sheets 1A, 1B, 2A, and 2B.

The Unit 1 system boundaries on SLR-8770-G-096 Sheets 1A, 1B, 2A, and 2B are the 1-DWS-12 pipe from the expansion tanks (1A1, 1A2, 1B1, and 1B2) and the continuations to drawing 8770-G-084 Sheet 1B.

The Unit 2 system boundaries on SLR-2998-G-084 Sheet 2 are the piping and piping components in the Unit 2 auxiliary building switchgear area and the piping and piping components in the diesel generator building from the wall to valves V38168, V38169, V38170, and V38171.

PSL Unit 1:
SLR-8770-G-096 Sheet 1A
SLR-8770-G-096 Sheet 1B
SLR-8770-G-096 Sheet 2A
SLR-8770-G-096 Sheet 2B

PSL Unit 2:
SLR-2998-G-084 Sheet 2

PSL Common:
SLR-8770-G-084 Sheet 1B

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

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

None

UFSAR References

9.2.5 (Unit 1)
9.2.3 (Unit 2)

Components Subject to AMR

Table 2.3.3-3 lists the DW system component types that require AMR and their associated component intended functions.

Table 3.3.2-3 provides the results of the AMR.

Table 2.3.3-3
Demineralized Makeup Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Piping	Leakage boundary (spatial)
Steel components	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial)

2.3.3.4 Diesel Generators and Support Systems

Description

The emergency diesel generators (EDGs) and support systems for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units.

The EDGs provide AC power to the onsite electrical distribution system to assure the capability for a safe and orderly shutdown and operation of plant safety equipment during an accident when the preferred offsite power supply is interrupted. Each diesel generator set consists of five distinguishable subsystems:

- Diesel engine/generator subsystem (includes intake and exhaust system)
- Air start subsystem
- Fuel oil subsystem
- Lube oil subsystem
- Cooling water subsystem

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on P&IDs and component system designations. There are no significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort.

The Unit 1 EDG system interfaces with the demineralized makeup water system at Expansion Tank 1A1 on SLR-8770-G-096 Sheet 1A.

The Unit 1 EDG system interfaces with the demineralized makeup water system at Expansion Tank 1A2 on SLR-8770-G-096 Sheet 1B.

The Unit 1 EDG system interfaces with the demineralized makeup water system at Expansion Tank 1B1 on SLR-8770-G-096 Sheet 2A.

The Unit 1 EDG system interfaces with the demineralized makeup water system at Expansion Tank 1B2 on SLR-8770-G-096 Sheet 2B.

The Unit 2 demineralized makeup water system does not directly connect to the EDG cooling water system.

PSL Unit 1:
EDG Fuel Oil
SLR-8770-G-086 Sheet 1

EDG Air Intake and Exhaust/Cooling Water/Lube Oil
SLR-8770-G-096 Sheet 1A
SLR-8770-G-096 Sheet 1B
SLR-8770-G-096 Sheet 2A
SLR-8770-G-096 Sheet 2B

EDG Starting Air
SLR-8770-G-096 Sheet 1C
SLR-8770-G-096 Sheet 2C

PSL Unit 2:
EDG Fuel Oil
SLR-2998-G-086 Sheet 1

EDG Air Intake and Exhaust/Cooling Water/Lube Oil
SLR-2998-G-096 Sheet 1A
SLR-2998-G-096 Sheet 1B
SLR-2998-G-096 Sheet 2A
SLR-2998-G-096 Sheet 2B

EDG Starting Air
SLR-2998-G-096 Sheet 1C
SLR-2998-G-096 Sheet 2C

PSL Common:

None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) The diesel generator system shall start automatically during a loss of reactor coolant accident to mitigate the consequences of the accident, in the event the preferred power source is interrupted.

(2) The diesel generator system shall supply reliable power to those electrical loads that are needed to achieve safe shutdown or to mitigate the consequences of a Design Basis Accident assuming any single active failure.

(3) The Unit 2 diesel generator system shall be capable of powering the normal Unit 2 loss of offsite power loads while simultaneously supporting safe shutdown of Unit 1 during a station Blackout on Unit 1.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 FP (Units 1 and 2) and SBO (Unit 2 only).

<u>UFSAR References</u>

8.3 and 9.5 (Unit 1)

8.3 and 9.5 (Unit 2)

<u>Components Subject to AMR</u>

Table 2.3.3-4 lists the diesel generator and support system component types that require AMR and their associated component intended functions.

Table 3.3.2-4 provides the results of the AMR.

Table 2.3.3-4
Diesel Generators and Support System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Air motor	Pressure boundary
Air motor lubricator	Pressure boundary
Bolting	Mechanical closure
Expansion joint	Pressure boundary
Flame arrestor	Flame suppression
Flexible hose	Pressure boundary
Heat exchanger (lube oil)	Heat transfer Pressure boundary
Heat exchanger (radiator)	Heat transfer Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Pump casing (cooling water)	Pressure boundary
Pump casing (engine-driven fuel)	Pressure boundary
Pump casing (fuel oil transfer)	Pressure boundary
Pump casing (lube oil)	Pressure boundary
Pump casing (priming)	Pressure boundary
Sight glass	Pressure boundary
Silencer	Pressure boundary
Strainer	Filter Pressure boundary
Tank (air start)	Pressure boundary
Tank (day)	Pressure boundary
Tank (diesel oil storage)	Pressure boundary
Tank (expansion)	Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

2.3.3.5 Fire Protection / Service Water

Description

The majority of fire protection / service water systems are common to Units 1 and 2. Those portions of fire protection/service water that are unit specific are essentially identical on both units. Unit 2 has a yard sump system (part of service water system) that is in scope.

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 system are addressed within the individual systems for those components.

The principal components of the fire protection system are the city water storage tanks (CWSTs), main firewater loop, motor-driven fire pumps, hose stations, hydrants, hoses, spray nozzles, sprinkler heads, and the associated piping and valves to support the system functions. The sensing tube portion of the Incipient Fire Detection (IFD) system is included in the fire protection system. Also included is the fixed halon gas suppression system and the required gas cylinders, nozzles, and the associated piping and valves to support the halon system's intended functions. The fire protection system also provides an emergency source of water for makeup to the component cooling water surge tank.

Additionally, the fire protection system includes the reactor coolant pump oil collection system (RCPOCS) that contains leakage from the RCP motors' lubricating oil system to reduce the possibility of a fire in accordance with the requirements of NFPA 805. The principal components of the RCPOCS 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 the plant structures AMR. 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.

Service water supports fire protection by maintaining pressure on the fire water system during normal plant operations. Also, NNS Unit 2 yard sump pump is required to mitigate plant flooding. Service water is a common site water supply for Units 1 and 2.

The principal components of the service water system are the hydropneumatic tank, motor-driven domestic water pumps, motor-driven yard sump pump, and the associated piping and valves to support the system functions.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed below. Significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort are as follows:

- The RCP oil collection systems (RCPOCS) have been redesigned and completely replaced on all the RCP motors on each Unit. In addition, the routing and size of the flexible hoses connecting to the drain piping to the oil collection tank was changed to accommodate the new design.
- On Unit 1, the RCPOCS guard pipes for the abandoned RCP motor oil reservoir level measurement system was disconnected from the RCPOCS and abandoned in place.

- FLEX fittings were added on an existing 6” connection at each of the 1A and 1B CWSTs for FLEX pump and fire pump suction. The portion of the affected piping and fittings were removed from SLR scope with the change.
- Boundary drawings SLR-2998-G-087 Sheet 1 and SLR-8770-G-087 Sheet 1 now include additional piping and components that have a leakage boundary (spatial) intended function.

The FP system interfaces with the Unit 1 CCW system at valve V15500 on SLR-8770-G-083 Sheet 1A.

The FP system interfaces with the Unit 2 CCW system at valve V15536 on SLR-2998-G-083 Sheet 1.

The FP system supply headers from the CWSTs 1A and 1B and fire pumps 1A and 1B to the main firewater loop are depicted on SLR-8770-G-084 Sheet 1A

The main firewater loop for the power block portion of the FP system is depicted on SLR-8770-G-084 Sheet 2. Fire water system valves V15185 and V15977 (Common), V15032, V15135, V15268, and V15774 (Unit 1), V15100, V15560, V15561, and V15568 (Unit 2) are the boundaries that separate the power block portion of the FP system from the non-power block portion.

The FP system supply to hose stations in the Unit 1 condensate polisher building is depicted on SLR-8770-G-087 Sheet 1.

The FP and SW systems are connected to CWSTs 1A and 1B on SLR-8770-G-084 Sheet 1A.

The SW system interfaces with the FP system at 12-FP-3 on SLR-8770-G-084 Sheet 2.

The FP system supply to Unit 1 hose stations and water suppression systems in the RAB and the turbine building is depicted on SLR-8770-G-087 Sheet 2.

The FP system supply to Unit 2 hose stations and water suppression systems in the RAB and the Turbine Building is depicted on SLR-2998-G-087 Sheet 1.

The Unit 1 SW system 10 CFR 54.4(a)(2) scope is depicted on SLR-8770-G-087 Sheet 1.

The Unit 2 SW system 10 CFR 54.4(a)(2) scope is depicted on SLR-2998-G-087 Sheet 1.

The Unit 2 yard sump, yard sump pump, and discharge piping and valves to the component cooling sump are depicted on SLR-2998-G-087 Sheet 1.

The Unit 1 RCP oil collection system is depicted on SLR-8770-G-091 Sheet 1.

The Unit 2 RCP oil collection system is depicted on SLR-2998-G-091 Sheet 1.

PSL Unit 1:
SLR-8770-G-083 Sheet 1A
SLR-8770-G-084 Sheet 1A
SLR-8770-G-084 Sheet 2
SLR-8770-G-087 Sheet 1
SLR-8770-G-087 Sheet 2
SLR-8770-G-091 Sheet 1

PSL Unit 2:
SLR-2998-G-083 Sheet 1
SLR-2998-G-087 Sheet 1
SLR-2998-G-091 Sheet 1

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

(2) Provide emergency source of water for makeup to the component cooling water surge tank.

FP, 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 FP.

UFSAR References

9.2.6, 9.5.1, and Appendix 9.5A (Unit 1)
9.2.4, 9.5.1, and Appendix 9.5A (Unit 2)

Components Subject to AMR

Table 2.3.3-5 lists the fire protection and 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
Fire Protection / Service Water System Components Subject to Aging Management Review

Component Type	Intended Function
Accumulator	Pressure boundary
Bolting	Mechanical closure
Drip pan	Direct flow
Fire hydrant	Pressure boundary
Flame arrestor	Fire prevention
Flexible hose	Pressure boundary
Hose reel	Pressure boundary
Nozzle	Pressure boundary Spray
Orifice	Pressure boundary Throttle
Piping	Leakage boundary (spatial) Pressure boundary
Pump casing (domestic water pump)	Pressure boundary
Pump casing (fire water pump)	Pressure boundary
Pump casing (yard sump pump 2A)	Pressure boundary
RCP oil collection	Pressure boundary
Sight glass	Pressure boundary
Steel components	Pressure boundary
Strainer	Filter Pressure boundary
Tank (City Water Storage Tanks)	Pressure boundary
Tank (Hydropneumatic Tank)	Pressure boundary
Tank (Nu-Matic Water-Control for Hydropneumatic Tank)	Pressure boundary
Tank (Unit 1 cable spreading room halon tank)	Pressure boundary
Tank (Unit 1 halon nitrogen tank)	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary
Vortex breaker	Vortex prevention

2.3.3.6 Fuel Pool Cooling

Description

The fuel pool cooling system is a closed loop system designed to maintain the fuel pool water temperature to within its established limits.

The fuel pool cooling systems for PSL Units 1 and 2 are similar regarding the function and type of components installed on each unit. The major differences between the fuel pool system of PSL Units 1 and 2 are concerning the codes utilized for the design and construction of these systems and the number of components installed on each Unit [e.g. two (2) fuel pool heat exchangers installed on Unit 2 versus one (1) fuel pool heat exchanger on Unit 1]. Additionally, the portion of the component cooling water (CCW) system piping that supplies cooling water to the

Unit 1 fuel pool heat exchanger is classified as NNS, while on Unit 2 this portion of the CCW system is classified Quality Group "C".

The fuel pool cooling system consist of two half-capacity fuel pool pumps and full-capacity fuel pool heat exchangers (one for Unit 1 and two for Unit 2). The fuel pool water is drawn from near the surface of the fuel pool and is circulated through one of the fuel pool heat exchangers where heat is rejected to the CCW system. From the outlet of the fuel pool heat exchanger, the cooled water is returned to the bottom of the fuel pool via a distribution header.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed below. Additional boundary drawings SLR 8770-G-078 Sheet 105C and SLR 2998-G-078 Sheet 105C have been added and show the fuel pool pumps. There are no significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort, but a few minor changes were made as follows:

SLR 8770-G-078 Sheet 140 and SLR 2998-G-078 Sheet 140 have both had a valve added to the cooling loop used for a FLEX connection point. Both drawings have also had the heat exchangers redrawn to show the correct type of heat exchanger.

PSL Unit 1:
SLR-8770-G-078 Sheet 105C
SLR-8770-G-078 Sheet 140

PSL Unit 2:
SLR-2998-G-078 Sheet 105C
SLR-2998-G-078 Sheet 140
SLR-2998-G-083 Sheet 1

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Maintain fuel pool pressure boundary for both units.

(2) Remove Unit 2 decay heat from the spent fuel.

(3) Provide a barrier for both Units to prevent the release of fission products to the environment.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

None

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

None

UFSAR References

9.1.3 (Unit 1)
9.1.3 (Unit 2)

Components Subject to AMR

Table 2.3.3-6 lists the fuel pool cooling system component types that require AMR and their associated component intended functions.

Table 3.3.2-6 provides the results of the AMR.

Table 2.3.3-6
Fuel Pool Cooling System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Heat exchanger (spent fuel pool)	Pressure boundary Heat transfer (Unit 2 Only)
Piping	Pressure boundary
Pump casing (spent fuel pool)	Pressure boundary
Steel components	Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

2.3.3.7 Instrument Air / Miscellaneous Bulk Gas Supply

Description

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

Instrument air system is designed to provide the required supply of dry, oil-free air at the required pressure for pneumatically operated valves, instruments, and controls.

Instrument air for each Unit consists of four compressors, each having a separate inlet filter, aftercooler, and moisture separator. The instrument air compressors discharge to a single header connected to an air receiver and two full capacity air dryer and filter assemblies. The system supply header is divided into branch lines supplying the intake structure, service building, water treatment area, turbine building, tank storage areas, fuel handling building, steam generator blowdown building, containment building and the reactor auxiliary building. The various air operated valves and pneumatic instruments and controls are supplied from the header.

Miscellaneous bulk gas supply consists of various storage facilities and associated components for supplying hydrogen, carbon dioxide, and nitrogen required for plant operation.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed below. Significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort are as follows.

- The original 1A and 1B instrument air compressors have been replaced with new compressor skids. The new compressor skids include intercoolers, aftercoolers, oil coolers, water separators and all associated lubricating oil components. All components within the compressor skids shown on the boundary drawing rectangles are considered to be part of a complex assembly and are not subject to AMR consistent with discussion in NUREG-2192 Table 2.1-2 and Section 2.1.5.1. The complex assembly boundaries are at the turbine cooling water connections to the coolers, at the water separator drains and valves, and at valves SH18332, PCV182330, SH182333, and PCV182331. Because the new compressor skids have integrated aftercoolers as compared to the original compressors which had separate aftercoolers, the aftercoolers are no longer subject to AMR.

- The Unit 2 instrument air compressor crosstie between Unit 1 and Unit 2 and the Unit 2 IA compressors are no longer required for Unit 1 Safe Shutdown. The removal of the Unit 2 IA compressors and associated piping and valves from within the license renewal boundary has removed P&ID 2998-G-085 Sheet 3 from the boundary drawings.

The instrument air system interfaces with the main steam system for Unit 1 on SLR-8770-G-079 Sheet 1 at coordinates B-4 and G-4 at HCV-08-2A and HCV-08-2B. For Unit 2, the instrument air system interfaces with the main steam system on SLR-2998-G-079 Sheet 7 coordinates at D-2 and H-2 between SZ-18-4 and SZ-18-5 and the main steam piping.

The instrument air system interfaces with the turbine control water system for Unit 1 on SLR-8770-G-089 Sheet 2 at coordinates B-5 and D-5 in instrument air compressors skids 1A and 1B.

The instrument air system interfaces with the HVAC system for Unit 1 on SLR-8770-G-878 at coordinates C-15 for FCV-25-7 and FCV-25-8, at C-7 for FCV-25-5, and at C-3 for FCV-25-2. For Unit 2, the interface with the HVAC system is on SLR-2998-G-878 at coordinates C-14 for FCV-25-7 and FCV-25-8, at C-7 for FCV-25-5, and at C-3 for FCV-25-2.

The miscellaneous bulk gas system interfaces with the sampling system for Unit 1 on 8770-G-092 Sheet 1 at coordinates D-6 at the V29383 valve and N2-39A pipe segment and at E-6 with the hydrogen sampling cubicles. For Unit 2 on 2998-G-092 Sheet 1A at coordinates E-6 the hydrogen sampling cubicles.

The miscellaneous bulk gas system interfaces with the containment spray system for Unit 2 on 2998-G-088 Sheet 1 at coordinates F-2 at pipe N2-23B and the hydrazine storage tank.

<u>PSL Unit 1:</u>
SLR-8770-G-079 Sheet 1
SLR-8770-G-085 Sheet 2A
SLR-8770-G-085 Sheet 2B
SLR-8770-G-085 Sheet 2C
SLR-8770-G-085 Sheet 3
SLR-8770-G-085 Sheet 4A
SLR-8770-G-092 Sheet 1
SLR-8770-G-878

<u>PSL Unit 2:</u>
SLR-2998-G-079 Sheet 7
SLR-2998-G-085 Sheet 2A
SLR-2998-G-085 Sheet 2B
SLR-2998-G-085 Sheet 2C
SLR-2998-G-087 Sheet 2
SLR-2998-G-088 Sheet 1
SLR-2998-G-092 Sheet 1
SLR-2998-G-878

<u>PSL Common:</u>
SLR-3509-G-117 Sheet 2

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Boundary of several containment penetrations and provide a containment integrity function.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

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

(1) Perform a function that demonstrates compliance with the FP (Unit 2 Only), EQ Program (Unit 1 and 2) and SBO (Unit 1 only).

<u>UFSAR References</u>

9.3.1 (Unit 1)
9.3.1 (Unit 2)

Components Subject to AMR

Table 2.3.3-7 lists the instrument air and bulk gas systems component types that require AMR and their associated component intended functions.

Table 3.3.2-7 provides the results of the AMR.

Table 2.3.3-7
Instrument Air / Miscellaneous Bulk Gas Supply System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator	Pressure boundary
Bolting	Mechanical closure
Filter	Filter Pressure boundary
Flexible hose	Pressure boundary
Instrument Air Dryer 1A (Unit 1 Only)	Pressure boundary
Instrument Air Dryer 1B (Unit 1 Only)	Pressure boundary
Instrument Air Receiver (Unit 1 Only)	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Rupture disk	Pressure boundary
Sight glass	Pressure boundary
Silencer (Unit 1 Only)	Pressure boundary
Steel components	Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

2.3.3.8 Intake Cooling Water/ Emergency Cooling Canal

Description

The intake cooling water (ICW) systems for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units.

The ICW system removes heat from the component cooling water (CCW) heat exchangers, open blowdown cooling system heat exchangers, and the turbine cooling water heat exchangers and discharges into the discharge canal. The system is divided into two independent and redundant supply headers along with an associated ICW pump to form two trains of ICW. The ICW system has a third ICW pump that can be used as a substitute pump for either train. The ICW system serves as a backup to the spent fuel pool make-up system.

Safety related portions of the ICW System start at each ICW pump suction bell, continue through the tube side of the CCW HX and end at the discharge canal. This section of the ICW is within the GL 89-13 scope. Another portion includes the flow paths that provide a redundant make up water supply to the spent fuel pool.

The components and layout of the Unit 1 and Unit 2 ICW systems are essentially the same. However, there are differences associated with component materials. Accordingly, there are instances where the material to environment combinations are unique to one Unit or the other.

The emergency cooling canal (ECC) is also known as the ultimate heat sink (UHS) system. The ECC system supplies water to the ICW pumps from Big Mud Creek in the unlikely event that flow from the intake canal becomes restricted or blocked.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed below. There are no significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort, but a few changes were made as follows:

SLR 8770-G-082 Sheet 2 and SLR 2998-G-082 Sheet 2 have both had their strainers replaced with a new type of strainer which has caused much of their connecting piping and controls to be greatly modified. All four CCW heat exchangers have also had their relief valves and the associated inlet and discharge piping removed. The relief valves are not required because holes are drilled in downstream butterfly valve discs to preclude overpressurization.

The ICW system interfaces with the CCW system for Unit 1 on SLR-8770-G-082 Sheet 2 at the CCW heat exchangers 1A and 1B. The CCW heat exchangers are shown on the boundary drawing as within the system but are captured with the CCW AMR.

The ICW system interfaces with the CCW system for Unit 2 on SLR-2998-G-082 Sheet 2 at the CCW heat exchangers 2A and 2B. The CCW heat exchangers are shown on the boundary drawing as within the system but are captured with the CCW AMR.

PSL Unit 1:
SLR 8770-G-082 Sheet 1
SLR 8770-G-082 Sheet 2
SLR 8770-G-093

PSL Unit 2:
SLR 2998-G-082 Sheet 2

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) ICW system provides a heat sink for the Component Cooling Water system

(2) ICW system provides a backup saltwater supply for the spent fuel pool makeup.

(3) ECC System provides a back-up supply of water to the ICW System.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 FP program.

UFSAR References

9.2.1 (Unit 1 and 2)
9.2.7 (Unit 1)
9.2.5 (Unit 2)

Components Subject to AMR

Table 2.3.3-8 lists the ICW and ECC systems component types that require AMR and their associated component intended functions.

Table 3.3.2-8 provides the results of the AMR.

Table 2.3.3-8
Intake Cooling Water / Emergency Cooling Canal System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Expansion joint	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing (Intake cooling water)	Pressure boundary
Steel components	Pressure boundary
Strainer	Filter Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

2.3.3.9 Primary Makeup Water

Description

For the purposes of SLR, the primary makeup water (PMW) system includes both demineralized water system and primary makeup water system components. This system provides treated, demineralized water to various systems throughout the plant for both Units including the reactor coolant and condensate systems.

Components common to both Units include the treated water storage tank (TWST) along with piping and components upstream and downstream of the treated water transfer pumps. Water from the TWST is used as a makeup source for the condensate storage tanks to maintain water supply for the auxiliary feedwater pumps per the NFPA 805 design basis.

For Unit 1, in scope PMW components include NNS valves, piping and piping components in the mechanical penetration room that have a leakage boundary (spatial) intended function. Unit 1 also includes SR piping and valves that support a containment isolation intended function.

For Unit 2, in scope components include the NNS primary water storage tank (PWST) along with piping and components upstream and downstream of the primary water pumps. These components are in scope because water from the PWST is credited for supplying hose stations inside containment and the Unit 2 fuel handling building for fire suppression purposes. Boundary valves that are required to be closed so water is not diverted to the hose stations are also in scope. Unit 2 also includes SR piping and valves that support a containment isolation intended function.

A complete list of PMW components requiring an aging management review and the component intended functions are provided in Table 2.3.3-9. The aging management review for primary makeup water is discussed in Section 3.3.2.1.9.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed below. Some changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort are as follows:

- The TWST, downstream piping, piping components and the treated water transfer pumps were added in scope on SLR-8770-G-084 Sheet 1B for subsequent license renewal since this tank provides a backup source for the Unit 2 CST for per NFPA 805 design basis.

The Unit 2 system boundary between the PMW system and the reactor coolant system on SLR-2998-G-078 Sheet 109 is at V1411 at coordinate A-7.

PSL Unit 1:
SLR-8770-G-084 Sheet 1C

PSL Unit 2:
SLR-2998-G-078 Sheet 109
SLR-2998-G-078 Sheet 121B
SLR-2998-G-080 Sheet 1A
SLR-2998-G-084 Sheet 1
SLR-2998-G-084 Sheet 2
SLR-2998-G-088 Sheet 1

PSL Common:
SLR-8770-G-084 Sheet 1B

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides containment isolation.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 FP and the EQ Program (Unit 2 only).

UFSAR References

9.2.5 (Unit 1)
9.2.3 (Unit 2)

Components Subject to AMR

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

Table 3.3.2-9 provides the results of the AMR.

Table 2.3.3-9
Primary Makeup Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Expansion joint (Unit 2 only)	Pressure boundary
Flow element	Pressure boundary
Hose reel (Unit 2 only)	Pressure boundary
Nozzle (Unit 2 only)	Pressure boundary Spray
Orifice	Pressure boundary Throttle
Piping	Leakage boundary (spatial) (Unit 1 only) Pressure boundary
Piping and piping components	Structural integrity (attached)
Pump casing (primary water storage) (Unit 2 only)	Pressure boundary
Pump casing (treated water transfer)	Pressure boundary
Steel components	Leakage boundary (spatial) (Unit 1 only) Pressure boundary
Strainer	Filter Pressure boundary
Tank (primary water storage) (Unit 2 only)	Pressure boundary
Tank (treated water storage)	Pressure boundary
Valve body	Leakage boundary (spatial) (Unit 1 only) Pressure boundary
Vortex breaker[1.]	Vortex prevention

Note:

1. The vortex breaker is located in the Unit 2 PWST.

2.3.3.10 Sampling

Description

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

The sampling system contains Units 1 and 2 SR and NNS valves, piping, and piping components. The sampling system provides the means to maintain containment integrity, maintain reactor coolant pressure boundary, and obtain samples from the reactor coolant system and auxiliary systems during normal plant startup, power operation and plant shutdown for chemical and radiochemical laboratory analysis. In addition, the sampling system provides a pressure integrity boundary at the connections to emergency core cooling systems, such as the shutdown cooling and safety injection systems (including the safety injection tanks). The results of analyses performed on these samples form the basis for regulating the boron concentration, monitoring the fuel integrity, evaluating the ion exchanger and filter performance, specifying chemical additions, and maintaining the proper hydrogen concentration in the reactor coolant system.

Typical analyses performed on the reactor coolant system and auxiliary systems include tests for boron concentration, fission and corrosion product activity levels and concentration, dissolved gas and corrosion product concentrations, chloride concentration, coolant pH and conductivity levels. The sampling room, located in the reactor auxiliary building, contains instrumentation to monitor the temperature and pressure of the samples from the following systems: reactor coolant system, safety injection system, shutdown cooling system and the chemical and volume control system.

A complete list of sampling system component types requiring an aging management review and the component intended functions are provided in Table 2.3.3-10. The aging management review for the sampling system is discussed in Section 3.3.2.1.10.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed below. Some changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort are as follows:

- Valves V5309 and V5310 were added to the boundary on SLR-2998-G-078 Sheet 153.
- Boundary drawings SLR-8770-G-078 Sheet 150 and SLR-2998-G-078-Sheets 150 and 153 now include additional piping and components that have a leakage boundary (spatial) intended function.

The Unit 1 sampling system interfaces with the reactor coolant system at valves V1210 and V1238 on SLR 8770-G-078 Sheet 110A and valve V1211 on SLR 8770-G-078 Sheet 110B.

The Unit 1 sampling system interface with the chemical and volume control system on SLR-8770-G-078 Sheet 120A at valves V2420, V2396, V2353, and V2366.

The Unit 1 sampling system interfaces with the safety injection system at valves V3443 and V3467 on SLR 8770-G-078 Sheet 120A and lines I-1-SI-435, 441, 447, and 452 on SLR-8770-G-078 Sheet 131B.

The Unit 2 sampling system interfaces with the reactor coolant system on SLR-2998-G-078 Sheet 108 at valve V1238, on SLR-2998-G-078 Sheet 109 at valve V1210, and on SLR-2998-G-078 Sheet 110 at valve V1213.

The Unit 2 sampling system interfaces with the chemical and volume control system on SLR-2998-G-078 Sheet 120 at valves V2420, V2396, V2353, and V2366.

The Unit 2 sampling system interfaces with the safety injection system on SLR-2998-G-078 Sheet 130B at valves V3502, V3443, V3467, and V3499, on

SLR-2998-G-078 Sheet 131 at valve V3485, and on SLR-2998-G-078 Sheet 132 at lines I-1-SI-435, 441, 447, and 452.

The Unit 2 sampling system interfaces with the hydrogen sample system on SLR-2998-G-092 Sheet 1 at lines I-3/8-HS-12 and I-3/8-HS-13.

PSL Unit 1:
SLR-8770-G-078 Sheet 110A
SLR-8770-G-078 Sheet 110B
SLR-8770-G-078 Sheet 120A
SLR-8770-G-078 Sheet 130B
SLR-8770-G-078 Sheet 131A
SLR-8770-G-078 Sheet 131B
SLR-8770-G-078 Sheet 150

PSL Unit 2:
SLR-2998-G-078 Sheet 108
SLR-2998-G-078 Sheet 109
SLR-2998-G-078 Sheet 110
SLR-2998-G-078 Sheet 120
SLR-2998-G-078 Sheet 130B
SLR-2998-G-078 Sheet 131
SLR-2998-G-078 Sheet 132
SLR-2998-G-078 Sheet 150
SLR-2998-G-078 Sheet 153
SLR-2998-G-092 Sheet 1

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides pressure integrity boundary at the connections to emergency core cooling systems, such as the shutdown cooling and safety injection systems (including the SI tanks) and reactor coolant system, from which the samples are taken.

(2) Provides containment integrity.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 FP, the EQ Program (Unit 2 only), and SBO (Unit 1 only).

UFSAR References

9.3.2 (Unit 1)
9.3.2 (Unit 2)

Components Subject to AMR

Table 2.3.3-10 lists the sampling system component types that require AMR and their associated component intended functions.

Table 3.3.2-10 provides the results of the AMR.

Table 2.3.3-10
Sampling System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Structural integrity (attached)
Steel components	Leakage boundary (spatial) Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.11 Turbine Cooling Water

Description

The turbine cooling water (TCW) systems for Units 1 and 2 are essentially identical with the exception that Unit 1 has a closed cooling loop for the 1A and 1B instrument air compressors. On this basis, the following discussion applies to both units.

The TCW system is designed to provide a heat sink for power cycle equipment during normal operation and normal shutdown.

TCW for each Unit is a closed-loop system which uses demineralized water with a corrosion inhibitor to remove heat from the turbine and other components in the power cycle. The turbine cooling water system consists of two heat exchangers, two pumps, one surge tank, and associated piping, valves, and instrumentation. During normal operation, water is circulated by one running turbine cooling water pump and the heat removed is transferred to the intake cooling water system through the two turbine cooling water heat exchangers. The heat exchanger interfaces with the intake cooling water system.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&ID and component system designations. The SLR boundaries are reflected on the SLR boundary drawing listed below. Significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort are that the service air compressors have been removed so the turbine cooling water system no longer interfaces with the service air system. In addition, the 1A and 1B instrument air compressors have been replaced and the new air compressor skids are now treated as complex assemblies as discussed in Section 2.3.3.7. The turbine cooling water piping on the compressor skid is also considered to be part of the complex assembly shown on drawing SLR-8770-G-089 Sheet 2.

The Unit 1 portion of the turbine cooling water system that is required to cool the 1A and 1B air compressor components are the only portion of the system in the scope of SLR because the 1A and 1B air compressors are needed for station blackout.

PSL Unit 1:
SLR-8770-G-089 Sheet 2

PSL Unit 2:
None

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

None

FP, 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 SBO (Unit 1 only).

UFSAR References

9.2.4 (Unit 1)
9.2.7 (Unit 2)

Components Subject to AMR

Table 2.3.3-11 lists the turbine cooling water system component types that require AMR and their associated component intended functions.

Table 3.3.2-11 provides the results of the AMR.

Table 2.3.3-11
Turbine Cooling Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Heat exchanger (instrument air fan cooler)	Heat transfer Pressure boundary
Piping	Pressure boundary
Pump casing (instrument air compressor cooling water recirculation)	Pressure boundary
Sight glass	Pressure boundary
Tank (instrument air compressor cooling water head)	Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

2.3.3.12 Ventilation

Description

The ventilation systems for Units 1 and 2 are essentially identical except as delineated below. On this basis, the following discussion applies to both units.

Ventilation provides for heating, ventilation, and air conditioning to various buildings and rooms/areas throughout the plant. Ventilation includes the following subsystems: control room air conditioning, emergency core cooling systems area ventilation, fuel handling building ventilation (Unit 2 only), intake structure ventilation (Unit 2 only), miscellaneous ventilation (Unit 1 only), reactor auxiliary building electrical and battery room ventilation, reactor auxiliary building main supply and exhaust, reactor cavity cooling, reactor support cooling and shield building ventilation.

Control room air conditioning is designed to maintain habitability, temperature, and humidity inside each control room. During normal operation, control room air conditioning for each Unit draws air from its associated control room, passes air through air handling units, and returns the air to the control room. In addition, outside makeup air is supplied to ensure that a positive pressure is maintained in the control room. Under emergency conditions, on receipt of a containment isolation signal, on receipt of a high radiation alarm on the intake radiation monitors, or on loss of power to the intake radiation monitors, outside air is isolated and the control room air is recirculated. A portion of the recirculated control room air is passed through high-efficiency particulate air filters and charcoal adsorbers.

In accordance with Table 2.1-2 of NUREG-2192, the condensers for the Unit 2 control room air conditioning system, which are cooled by component cooling water, are considered to be part of a complex refrigerant air conditioning assembly, and are tested to ensure they function as intended. Therefore, these air conditioning Units are on dedicated skids and are not subject to AMR. The CCW system piping and piping components connected to these condensers are subject to AMR. These components are addressed in the CCW AMR.

Emergency core cooling systems area ventilation is designed as the necessary ventilation for the emergency core cooling systems area under accident conditions. This subsystem provides post-loss-of-coolant accident (LOCA) high-efficiency particulate filtration and iodine adsorption for air exhausted from the emergency core cooling systems areas.

Fuel handling building ventilation (Unit 2 only) is designed to prevent buildup of airborne radioactivity in the building and ventilates the fuel pool cooling equipment contained in the building. During emergency operation, the subsystem is designed to automatically isolate and utilize shield building ventilation to remove and filter air from the fuel pool area.

Intake structure ventilation (Unit 2 only) is designed to ventilate the intake cooling water pump enclosure. Two 100 percent capacity, independently powered exhaust fans ventilate the enclosure.

Miscellaneous ventilation (Unit 1 only) provides ventilation for the Unit 1 computer room and the Unit 1 hot shutdown panel room.

Reactor auxiliary building electrical and battery room ventilation is designed as the primary intake and exhaust for air in the electrical equipment and battery rooms. The electrical equipment rooms are ventilated by a once-through filtered ventilation system that contains separate supply and exhaust fans.

Reactor auxiliary building main supply and exhaust is designed as the primary intake and exhaust for air in each of the reactor auxiliary buildings. The subsystems are designed to limit the temperature to an ambient temperature of 104°F in the equipment areas with an outside temperature of 93°F. The reactor auxiliary buildings are ventilated by once-through filtered ventilation that contains separate supply and exhaust fans. The exhaust system serves no safety function.

The reactor cavity cooling system is designed to ventilate the annular space between the reactor vessel and the concrete primary shield wall to limit the concrete surface temperature to a maximum of 150°F to minimize the possibility of concrete dehydration and consequent faulting. The cooling system limits thermal growth of the supporting steel work, in conjunction with the reactor support cooling system.

The purpose of the reactor support cooling system (in conjunction with the reactor cavity cooling system) is to limit the temperature at the bottom of the lubrication plate between the reactor and support leg to 300°F, restrict thermal growth of the reactor vessel supporting steelwork to 3/16-inch by limiting surface temperature to 140°F and limit the temperature at steel concrete interfaces to 150°F.

Shield building ventilation maintains a slight negative pressure in each of the shield building annuli following a LOCA. Shield building ventilation mixes building in-leakage with the air in the annuli and any leakage from each of the containments and discharges it through filter trains that include charcoal adsorbers. The plant vent stacks are considered part of their respective shield building ventilation systems. However, considering PSL Units 1 and 2 accident analyses assume ground level releases, the plant vent stacks do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 and therefore are not within the scope of license renewal.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on P&IDs and component system designations. There are no significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort. Two additional ventilation systems were added to the scope (reactor cavity cooling, reactor support cooling) as non-safety systems required to support a SR function. Also, the ventilation for the Unit 1 hot shutdown panel continues to be in the scope but is not shown on the drawings. The drawings for the original LR added a sketch from an air flow diagram. The drawings for SLR are unmodified P&IDs. In addition, pressure instrumentation was added to the Unit 1 control room pressure boundary and is shown on the P&IDs.

The Unit 2 ventilation system interfaces with the CCW system at control room air conditioning on SLR-2998-G-083 Sheet 2.

PSL Unit 1:
SLR-8770-G-878
SLR-8770-G-879

PSL Unit 2:
SLR-2998-G-878
SLR-2998-G-879 Sheet 2
SLR-2998-G-879 Sheet 3

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) SCs that are SR and are relied upon to remain functional during and following design basis events

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 EQ, FP, and SBO (Unit 1).

UFSAR References

6.2 and 9.4 (Unit 1)
6.2 and 9.4 (Unit 2)

Components Subject to AMR

Table 2.3.3-12 lists the ventilation 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
Ventilation System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Demister	Moisture removal
Duct	Pressure boundary
Fan housing	Pressure boundary
Flex connection	Pressure boundary
Housing	Pressure boundary
Housing supports	Structural support
HVAC Closure bolting	Mechanical closure
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Structural integrity (attached)
Steel components	Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

2.3.3.13 Waste Management

Description

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

Waste management system collects, monitors, and processes potentially radioactive reactor plant wastes prior to release or removal from the plant site. Waste management includes three subsystems: liquid, gaseous, and solid waste management. Waste management also includes the safeguards pump room drains and equipment and floor drainage.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. The SLR boundaries are reflected on the SLR boundary drawings listed below. The only significant difference between these boundaries and the boundaries identified as part of the original PSL license renewal effort is that orifices were added to the lines containing the reactor auxiliary building floor drain valves that isolate flow to the emergency core cooling system pump rooms.

PSL Unit 1:
SLR-8770-G-078 Sheet 160A
SLR-8770-G-078 Sheet 163A
SLR-8770-G-078 Sheet 163B
SLR-8770-G-088 Sheet 1

PSL Unit 2:
SLR-2998-G-078 Sheet 160A
SLR-2998-G-078 Sheet 163A
SLR-2998-G-078 Sheet 163B
SLR-2998-G-088 Sheet 1

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Maintains containment integrity.

(2) Isolate the safeguards pump rooms in the event of a ruptured line.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

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

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

UFSAR References

9.3.3, 11.2.2, 11.3.2, and 11.5.2 (Unit 1)
9.3.3, 11.2.2, 11.3.2, and 11.4.2 (Unit 2)

Components Subject to AMR

Table 2.3.3-13 lists the waste management system component types that require AMR and their associated component intended functions.

Table 3.3.2-13 provides the results of the AMR.

Table 2.3.3-13
Waste Management System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Cleanout plug	Pressure boundary
Drain	Pressure boundary
Drain cover	Filter
Orifice	Pressure boundary Throttle
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Structural integrity (attached)
Steel components	Leakage boundary (spatial) Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.4 Steam and Power Conversion System

2.3.4.1 Main Steam

Description

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

The primary function of the main steam system is to transport steam from the steam generators and deliver it to the high pressure turbine, moisture separator reheaters (MSR), and the auxiliary feedwater (AFW) pump turbine and other secondary systems and components. The main steam system provides overpressure protection for the steam generators. The main steam system provides reactor coolant system decay heat removal capability via the atmospheric dump valves and/or the main steam safety valves. The main steam system starts at the shell side of the steam generators and ends at the HP turbine, MSRs and the turbine driven AFW pump.

Auxiliary steam provides pressure-regulated and unregulated steam to plant auxiliary loads. Auxiliary steam isolates in certain high-energy line break scenarios.

The turbine for each unit, which includes the associated generator, converts the steam input from main steam to the plant's electrical output and provides first-stage pressure input to the reactor protection system.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. Changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort resulted from the replacement of the Unit 1 MSIV actuators. The new actuators, which use pneumatically-driven hydraulic fluid to open the valve and gas to close the valve, are subject to testing during outages and are therefore treated as complex assemblies. The gas line that runs to the vendor-supplied actuator components is in scope and results in the addition of new boundary components. Additionally, the Unit 2 MSIV air supply components which are part of the main steam system were included with the instrument air AMR for the original license renewal but are now included in this AMR.

Interfaces between the boundaries of other systems with those of main steam, auxiliary steam, and turbine system boundaries are described below:

- The main steam boundary interfaces with the auxiliary feedwater boundary at the auxiliary feedwater pump turbine on drawings SLR-2998-G-080 Sheet 2B, SLR-2998-G-079 Sheet 1, SLR-8770-G-079 Sheet 1, and SLR-8770-G-080 Sheet 4.
- Main steam interfaces with instrument air at HCV-08-2A/B (Unit 1 only) on drawing SLR-8770-G-079 Sheet 1.
- Main steam interfaces with instrument air at Unit 2 MSIV actuator components SZ-18-4 and SZ-18-5 on SLR-2998-G-079 Sheet 7.

The SLR boundaries are reflected on the SLR boundary drawings listed below.

PSL Unit 1:
SLR 8770-G-079 Sheet 1
SLR 8770-G-079 Sheet 2
SLR 8770-G-079 Sheet 5
SLR 8770-G-079 Sheet 7
SLR 8770-G-080 Sheet 4

PSL Unit 2:
SLR 2998-G-079 Sheet 1
SLR 2998-G-079 Sheet 2
SLR 2998-G-079 Sheet 6
SLR 2998-G-079 Sheet 7
SLR 2998-G-080 Sheet 2B

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provide steam generator isolation to control release of fission products following a steam generator tube rupture.

(2) Maintain containment integrity.

(3) Provide decay heat and sensible heat removal from the reactor coolant system.

(4) Prevent uncontrolled blowdown of both steam generators.

(5) Supply steam to the turbine driven auxiliary feedwater pump during normal and post-accident cooldown.

(6) Provide overpressure protection for the steam generators.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

(2) The turbine control system provides reactor trip signal to the reactor protective system upon occurrence of a turbine trip signal.

FP, 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 FP, the EQ Program, ATWS, and SBO.

UFSAR References

7.7, 10.2, 10.3 (Unit 1)
7.7, 10.2, 10.3 (Unit 2)

Components Subject to AMR

Table 2.3.4-1 lists the main steam system component types that require AMR and their associated component intended functions.

Table 3.4.2-1 provides the results of the AMR.

Table 2.3.4-1
Main Steam System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Filter (Unit 2 only)	Filter Pressure boundary
Flexible hose (Unit 1 only)	Pressure boundary
Orifice	Pressure boundary Throttle
Piping	Pressure boundary
Piping and piping components	Pressure boundary Structural integrity (attached)
Steam trap	Pressure boundary
Strainer (Unit 1 only)	Filter Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

2.3.4.2 Main Feedwater and Steam Generator Blowdown

Description

The main feedwater and steam generator blowdown systems for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units.

Main feedwater and steam generator blowdown provide sufficient water flow to the steam generators to maintain an adequate heat sink for the reactor coolant system, provide for main feedwater and steam generator blowdown isolation following a postulated LOCA or steam line break event, and assist in maintaining steam generator water chemistry.

Main feedwater supplies pre-heated, high-pressure feedwater to the steam generators at a rate equal to the main steam and steam generator blowdown flows. Two feedwater pumps operate in parallel to deliver feedwater through one stage of high-pressure feedwater heaters to the steam generators. The feedwater flow rate is regulated by a three-element controller that compares the feed flow, steam flow, and steam generator level.

Steam generator blowdown assists in maintaining required chemistry of the steam generator secondary side coolant by providing a means for removal of foreign matter that concentrates in the evaporator section of the steam generator.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. Significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort are as follows:

- The Unit 1 main feedwater regulating valves (FCV-9011 and FCV-9021) and their instrument air supply lines are no longer in scope on drawing SLR-8770-G-080 Sheet 3. These valves were required for fire protection safe shutdown during the LRA but have since been removed from the essential equipment list.
- For LRA, the pneumatic actuation system of the MFIVs was determined to include actuator components which were considered to be part of the MFIVs and therefore the FW system. For Unit 1, the nitrogen piping/tubing, and components upstream of the associated isolation valves were reviewed with the Instrument Air and Bulk Gas AMR (Section 3.3.2.1.7). For SLR, the Unit 1 boundary is adjusted to include all of the in-scope components on SLR-8770-G-080 Sheet 5 with the FW system.

There are significant differences in scope of the FW and SGBD systems between Unit 1 and Unit 2, as described below:

- The Unit 1 feedwater boundary extends beyond the MFIV actuator components to include the remaining nitrogen supply components identified as in scope on drawing SLR-8770-G-080 Sheet 5. The Unit 2 feedwater boundary does not extend beyond the MFIV actuator components.

- The Unit 1 feedwater boundary includes components in scope in accordance with 10 CFR 54.4(a)(2) which are in the turbine building and the yard. These components are identified on drawings SLR-8770-G-080 Sheet 2, SLR-8770-G-080 Sheet 3, and SLR-8770-G-081 Sheet 2. The Unit 2 feedwater boundary does not include components in scope in accordance with 10 CFR 54.4(a)(2).

The FW and SGBD systems interface with other in-scope systems as described below:

- The Unit 1 FW system interfaces with the CS system at feedwater pumps 1A and 1B and at valve V09217 on SLR-8770-G-080 Sheet 3. The interface between the FW and CS systems at the feedwater pumps is also shown on SLR-8770-G-080 Sheet 2.

- The Unit 1 FW system interfaces with the AFW system at valves V09135, V09119, V09157, and V09151 on SLR-8770-G-080 Sheet 4.

- The Unit 1 heater drains and vents system contains a small portion of piping and piping components shown on SLR-8770-G-081 Sheet 2 that are in scope for a leakage boundary (spatial) intended function. This small group of components are considered to be part of the feedwater and blowdown system.

- The Unit 2 FW system interfaces with the AFW system at valves MV-09-9, MV-09-10, MV-09-11, and MV-09-12 on SLR-2998-G-080 Sheet 2B.

The SLR boundaries are reflected on the SLR boundary drawings listed below.

<u>PSL Unit 1:</u>
SLR-8770-G-080 Sheet 2
SLR-8770-G-080 Sheet 3
SLR-8770-G-080 Sheet 4
SLR-8770-G-080 Sheet 5
SLR-8770-G-081 Sheet 2
SLR-8770-G-086 Sheet 1
SLR-3509-G-115 Sheet 1A

<u>PSL Unit 2:</u>
SLR-2998-G-080 Sheet 2A
SLR-2998-G-080 Sheet 2B
SLR-2998-G-086 Sheet 1
SLR-3509-G-115 Sheet 1B

<u>PSL Common:</u>
None

<u>System Intended Functions</u>

SR functions (10 CFR 54.4(a)(1)):

(1) Provide decay heat removal support using the auxiliary feedwater system following design basis events.

(2) Provide automatic containment isolation in the event of a loss of coolant accident or design basis event.

(3) Maintain integrity of the steam generator pressure boundary.

(4) Provide feedwater isolation in the event of a design basis event.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

FP, 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 FP, the EQ Program, and SBO.

<u>UFSAR References</u>

10.1, 10.4.6, and 10.4.7 (Unit 1)
10.3.6, 10.4.7, and 10.4.8 (Unit 2)

<u>Components Subject to AMR</u>

Table 2.3.4-2 lists the main feedwater and steam generator blowdown systems component types that require AMR and their associated component intended functions.

Table 3.4.2-2 provides the results of the AMR.

Table 2.3.4-2
Main Feedwater and Steam Generator Blowdown System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator	Pressure boundary
Bolting	Mechanical closure
Filter (Unit 1 only)	Filter Pressure boundary
Flexible hose (Unit 1 only)	Pressure boundary
Orifice	Leakage boundary (spatial) Pressure boundary Throttle
Piping	Leakage boundary (spatial) Pressure boundary
Piping and piping components	Leakage boundary (spatial) Pressure boundary Structural integrity (attached)
Pump casing (Feedwater pumps 1A and 1B)	Leakage boundary (spatial)
Steel components	Leakage boundary (spatial) Pressure boundary
Thermowell	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.4.3 Auxiliary Feedwater and Condensate

Description

The auxiliary feedwater and condensate systems for Units 1 and 2 are essentially identical. On this basis, the following discussion applies to both units.

The primary function of the auxiliary feedwater system is to ensure a sufficient supply of cooling water to the steam generators when main feedwater is not available. Portions of the condensate system provide the source of water for the auxiliary feedwater system. During normal plant operation, feedwater is supplied to the steam generators by the main feedwater system. The auxiliary feedwater system may be utilized during normal plant startup, hot standby, and cooldown. During plant startup and hot standby the system can provide a source of water inventory for the steam generators. During cooldown, the system can provide heat removal to bring the reactor coolant system to the shutdown cooling system entry conditions.

Boundary

For the purposes of this screening evaluation, the system boundaries were defined based on the P&IDs and component system designations. There are no significant changes between these boundaries and the boundaries identified as part of the original PSL license renewal effort.

Boundary drawings SLR-8770-G-080 Sheet 2 and SLR-8770-G-080 Sheet 3 now include additional piping and components that have a leakage boundary (spatial) intended function.

Interfaces between the SLR boundaries of other systems with those of auxiliary feedwater and condensate system boundaries are described below:

- The Unit 1 auxiliary feedwater system interfaces with the main steam system at the MV-08-3 on drawing 8770-G-079 Sheet 1.
- The Unit 1 condensate system interfaces with the demineralized water system at the condensate storage tank on 8770-G-080 Sheet 1.
- The Unit 1 condensate system interfaces with main feedwater at feedwater pumps 1A and 1B on 8770-G-080 Sheet 2.
- The Unit 1 auxiliary feedwater system interfaces with main feedwater at valves V09135, V09119, V09157, and V09151 on drawing 8770-G-080 Sheet 4.
- The Unit 2 auxiliary feedwater system interfaces with the main steam system at the MV-08-3 on drawing 2998-G-079 Sheet 1.
- The Unit 2 condensate system interfaces with the demineralized water system at the condensate storage tank on 2998-G-080 Sheet 1A.
- The Unit 2 auxiliary feedwater system interfaces with main feedwater at valves MV-09-9, MV-09-10, MV-09-11, and MV-09-12 on drawing 2998-G-080 Sheet 2B.

The SLR boundaries are reflected on the SLR boundary drawings listed below.

PSL Unit 1:
SLR 8770-G-079 Sheet 1
SLR 8770-G-080 Sheet 1
SLR 8770-G-080 Sheet 2
SLR 8770-G-080 Sheet 3
SLR 8770-G-080 Sheet 4

PSL Unit 2:
SLR 2998-G-079 Sheet 1
SLR 2998-G-080 Sheet 1A
SLR 2998-G-080 Sheet 2B

PSL Common:
None

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provide sensible and decay heat removal from the reactor coolant system during design basis events when main feedwater is not available.

(2) Provide auxiliary feedwater steam and feedwater isolation following a main steam line or feedwater line break.

(3) Provide sufficient capacity to reduce reactor coolant system temperature to entry conditions for shutdown cooling system during design basis events.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

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

(2) The cross-tie between the Unit 1 and Unit 2 condensate storage tanks is designed to provide water from Unit 2 to Unit 1 in the unlikely event of tornado missile damage.

FP, 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 FP, the EQ Program, ATWS, and SBO.

UFSAR References

10.4.6 and 10.5 (Unit 1)
10.4.7 and 10.4.9 (Unit 2)

Components Subject to AMR

Table 2.3.4-3 lists the auxiliary feedwater and condensate systems component types that require 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 and Condensate System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting	Mechanical closure
Filter (Unit 2 only)	Pressure boundary
Heat exchanger (auxiliary feedwater pump lube oil cooler) (Unit 2 only)	Heat transfer Pressure boundary
Orifice	Leakage boundary (spatial) (Unit 1 only) Pressure boundary Throttle
Piping	Leakage boundary (spatial) (Unit 1 only) Pressure boundary
Piping and piping components	Leakage boundary (spatial) Pressure boundary Structural integrity (attached)
Pump casing (auxiliary feedwater pump)	Pressure boundary
Pump casing (auxiliary feedwater lube oil pump) (Unit 2 only)	Pressure boundary
Sight glass (Unit 2 only)	Pressure boundary
Tank (condensate storage tank)	Pressure boundary
Tank (lube oil reservoir) (Unit 2 only)	Pressure boundary
Turbine casing	Pressure boundary
Valve body	Leakage boundary (spatial) (Unit 1 only) Pressure boundary
Vortex breaker	Vortex prevention

2.4 SCOPING AND SCREENING RESULTS: STRUCTURES

2.4.1 Containment Building Structures

Description

The Unit 1 and 2 containment building structures consist of the steel containment vessel surrounded by the reinforced concrete shield building. The containment vessel and the shield building are separated by an annular space. The annular space is approximately 4ft wide and it is provided to permit construction operations and in-service inspection and to filter any leakage from containment during loss of coolant accident. The containment building structures also house the other important engineered safety systems such as the safety injection system, heat removal systems, shield building ventilation system, containment isolation and the containment hydrogen control system that interface with the RCS. The structures provide biological shielding for both normal and accident situations.

The nominal 10-foot-thick concrete foundation slab supports the containment vessel and the concrete shield building. The reinforcing steel is placed in radial and circumferential directions except that a two-way reinforced circular core of 14 feet diameter is placed in the center portion of the slab. The radial and hoop reinforcing steel is designed to resist the radial loads and hoop loads respectively. Numerous mechanical and electrical systems penetrate the containment vessel through welded steel penetrations. The Unit 2 containment structure is essentially identical in design and construction to that of Unit 1.

Containment Vessel – The containment vessel is low leakage steel shell including all its penetrations, designed to confine the radioactive materials that could be released by accidental loss of integrity of the reactor coolant pressure boundary. The containment vessel is a 2-inch thick right circular cylinder with 1-inch thick hemispherical dome and 2-inch thick ellipsoidal bottom. It has an inside diameter of 140 ft and an inside height of 232 ft. The containment vessel houses the reactor pressure vessel, the reactor coolant piping and pumps, the steam generators, the primary coolant pressurizer and the pressurizer quench tank, and other branch connections of the reactor coolant system, including the safety injection tanks. It is also equipped with a dome inspection walkway, access ladder, and a circular crane girder with a crane rail attached to the shell of the vessel.

Containment vessel penetrations include a construction hatch, a maintenance hatch, a personnel air lock, an escape lock and various sized penetration nozzles. Containment penetration assemblies provide passage of process, service, sampling and instrumentation pipe lines and electrical cabling into the containment vessel while maintaining the desired containment integrity and providing a leak-tight seal with adequate provisions for movement between the pipe lines and the containment structure during operation, emergency and accident conditions. The containment vessel is enclosed by the reinforced concrete shield building.

Shield Building – The reactor shield building is a low leakage concrete structure that surrounds the steel containment vessel. It is a reinforced concrete right cylinder structure with a shallow dome roof surrounding the containment vessel. It protects the containment vessel from external missiles, provides biological shielding and a means for collecting fission products that may leak from the containment vessel following a hypothetical accident and provides environmental protection for the containment vessel. The shield building has an outside diameter of 154 ft and a height of 230.5 ft measured from the top of the base slab to the top of the dome. The reinforced concrete walls of the building are 3 ft thick. The thickness of the dome is 2 feet-6 inches. The shield building is a freestanding structure, with concrete fill placed in the bottom portion of the structure to support the steel containment vessel. To assure proper contact between the containment vessel and the fill concrete, the interface is grouted with epoxy.

Foundation Slab – The foundation slab supports the containment vessel and the shield building. The base mat is a 10 ft thick concrete dish-shaped slab with an over-all diameter of 160 ft. A circular flat slab of 57.5 ft diameter is located in the center portion of the slab inclining up with a slope of 4 horizontal to 1 vertical in an elevation difference of 10.5 ft. The base mat directly supports the shield building. The containment vessel is supported on fill concrete that transfers the loads by bearing to the base mat. A moisture barrier (1" joint sealer) is provided between the concrete floor and the steel vessel, inside and outside the vessel. The foundation slab of the containment vessel and the reinforced concrete shield building has no structural continuity with the foundation slab of any adjacent structure.

Fuel Transfer Tubes – The fuel transfer tube is provided to transport fuel assemblies between the refueling cavity inside the containment structure and the refueling canal in the fuel handling building during refueling operations. The penetration consists of the 36-inch diameter stainless steel fuel transfer tube installed in a 48-inch concentric carbon steel pipe sleeve. The fuel transfer tube is fitted with a double gasketed blind flange in containment and a standard gate valve in the fuel handling building. The outer pipe is welded to containment vessel and provisions are made for testing welds essential to the integrity of the containment vessel. Three bellows are provided in the containment and one bellows in the fuel handling building. A flexible membrane expansion joint is provided to compensate for the building settlement and differential motion between the containment vessel, the shield building and the fuel handling building. 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. Containment penetration assemblies provide for passage, service, sampling and instrumentation pipe lines and electrical cabling into containment vessel, while maintaining the desired containment integrity and providing a leak-tight seal with adequate provisions for movement between the pipe lines and the containment structure during operation, emergency, and accident conditions. Penetrations may also serve as support points for systems, such as piping passing through the containment boundary. Mechanical penetration assemblies typically consist of a containment vessel penetration nozzle, a process pipe, a shield building penetration sleeve, and a shield building bellows seal. Electrical penetration assemblies are used to provide the means for carrying electrical and instrumentation conductors through the containment vessel, the annulus and the shield building. Canister or header plate type penetration assemblies are used for all electrical conductors through the containment vessel, the annulus and the shield building. The primary containment penetration is inserted in the containment vessel nozzle and is field welded inside the steel vessel to form the sealing weld. The secondary seal is inserted in a nozzle embedded in the concrete shell of the shield building. The secondary seal is field welded to the nozzle in the shield building. All penetration assemblies are provided with means to pressurize the primary canisters for monitoring leakages.

Airlocks and Hatches – Two equipment hatches are provided for each containment vessel, a construction hatch (that has a permanently welded cover) and a maintenance hatch. These are welded steel assemblies with 28 ft diameter and 12 ft diameter clear openings respectively. The construction hatch for each Unit is a welded construction hatch cover. The maintenance hatch is a welded assembly with a double gasketed flanged and bolted hatch cover. The 12 ft diameter maintenance hatch is used to provide access to the containment vessel interior. It has a double gasketed flanged and bolted cover.

Two personnel airlocks are provided for each containment vessel. These are welded steel assemblies. Each airlock has a double gasketed door at each end of the tube. Provision is made to pressurize the space between the gaskets.

RCS Class 1 Supports – The interface between the containment structure and the Class 1 supports is at the containment structure's interior surfaces. The steel components comprising the support structure, including structure fasteners and the structure's anchorage fasteners, are part of the Class 1 support. The RCS Class 1 supports are composed of the following: reactor vessel supports; steam generator supports; RCP supports, pressurizer supports, and pressurizer surge line supports. The RCS Class 1 supports are designed to resist operating loads, pipe ruptures and seismic loads.

Containment Building Interior Components – The interior structures of the containment vessel and shield building consist of concrete and steel components. The major concrete internal components are the primary and secondary shield walls, the refueling cavity, the operating floor, and the enclosures around the pressurizer and steam generators. The major steel internal components are the Reactor Coolant System supports, the refueling cavity liner, steel framing, miscellaneous platforms, pipe whip restraints, and supports for cable trays, conduits, HVAC ducting and piping. The internal structures are supported on the concrete floor fill placed in the bottom of the steel containment. The entire RCS is located within the compartments formed by the concrete fill floor, the primary and secondary shield walls, and the concrete enclosures around the steam generators and pressurizer.

Boundary

The containment system structure boundary is defined by the external surfaces of the containment structure. The boundary includes the shield building, the annular space between the interior surface of the shield building and the external surface of the containment vessel, the containment vessel and the containment vessel interior concrete and steel components. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal effort.

System Intended Functions

SR 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 SR components.

3) Provide shelter/protection to SR components and provide a missile barrier to turbine and tornado-generated missiles.

NNS that could affect SR functions (10 CFR 54.4(a)(2)):

1) The containment building structures contain NNS SSCs which could potentially affect the satisfactory accomplishment of SR functions.

FP, 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 FP.
2) House and/or support EQ components and components relied on for PTS.

UFSAR References

2.3.1, 2.5.4, 3.8.2, 3.8.3, 3.8.4, 5.2.3, 6.2.1, 18.2.7, and 18.3.4 (Unit 1)
2.5.4, 3.8.2, 3.8.3, 3.8.4, 5.2.3, 6.2.1, 18.2.7, and 18.3.4 (Unit 2)

Subsequent License Renewal Drawings

None.

Components Subject to AMR

Table 2.4-1 lists the containment building structure component types that require an AMR and their associated component intended functions.

Table 3.5.2-1 provides the results of the AMR.

Table 2.4-1
Containment Building Structure
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Air locks, maintenance hatch and accessories	Fire barrier Pressure boundary
Construction hatch and cover	Fire barrier Pressure boundary
Containment vessel	Pressure boundary Structural support
Containment vessel moisture barrier	Shelter, protection
Containment vessel nozzles	Fire barrier Pressure boundary Structural support
Fuel transfer tube (including flexible membrane, penetration sleeves, expansion bellows/joints and blind flange)	Leakage barrier Fire barrier Pressure boundary Structural support
Interior beams, fill, shields, slabs, and walls	Missile barrier Radiation shielding Shelter, protection Structural support
Masonry walls	Shelter, protection Structural support
Miscellaneous steel (missile barriers, hatch frame covers, framing for radiant energy shields, etc.)	Fire barrier Missile barrier Shelter, protection Structural support
Penetration seals and gaskets	Pressure boundary
Penetrations (electrical)	Fire barrier Pressure boundary Structural support
Penetrations (mechanical), including bellows	Fire barrier Pressure boundary Structural support
Penetrations (mechanical), thermal insulation	Insulate (thermal)
Pressure retaining bolting	Pressure boundary Structural support
Primary shield wall	Radiation shielding Shelter, protection Structural support
RCS Class 1 supports	Structural support

Table 2.4-1
Containment Building Structure
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
RCS Class 1 support bolting	Structural support
Reactor cavity seal ring	Pressure boundary
Reactor cavity (sump) and refueling cavity liner plate	Pressure boundary
Reactor cavity (sump) and refueling cavity liner plate anchors and attachments	Pressure boundary Structural support
RV supports and bolting	Structural support
Service Level I coatings	Coating integrity
Shield Building airtight bulkhead door seals	Pressure boundary Shelter, protection
Shield Building exterior walls and roof	Radiation shielding Shelter, protection Structural support
Shield Building foundation / base mat	Shelter, protection Structural support
Shield Building outside door (maintenance hatch)	Shelter, protection
Sliding Surfaces	Structural support
*Trisodium Phosphate (TSP) baskets, Unit 2	Shelter, protection Structural support
*TSP Baskets in the Unit 2 Containment sump support pH control through dissolving as the post loss-of-coolant accident (LOCA) water level increases.	

2.4.2 Component Cooling Water Areas

<u>Description</u>

The Unit 1 and Unit 2 component cooling water areas house the SR component cooling water pumps and heat exchangers and are designed to seismic category 1 requirements. The concrete structure consists of a base mat and exterior walls.

The Unit 1 component cooling water area is an outdoor area, exposed to the environment, with pumps and heat exchangers supported on concrete pedestals well above flood and wave run-up elevations. Steel missile barriers are provided over the pumps.

The Unit 2 component cooling water area consists of an enclosed concrete building. The component cooling water pumps and heat exchangers are housed in a rectangular reinforced concrete missile protection structure. The concrete structure consists of a base mat, exterior walls, and a roof slab, supported on the exterior walls and reinforced concrete columns. The Unit 2 Component Cooling Water System equipment susceptible to flood damage is protected by locating all SR components above the maximum expected water level and wave run-up during a probable maximum hurricane.

Boundary

The component cooling water areas structures boundary includes all in-scope structural components that comprise the area within and including concrete walls. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal effort.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide structural support for SR SSCs located within the component cooling water areas. Provide protection of SR SSCs located within the component cooling water areas from elements of the outside environment (including externally generated missiles and external flooding).

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provide structural support to NNS components whose failure could prevent satisfactory accomplishment of any of the SR CCW system components. The component cooling water areas contain NNS structural components that could potentially interact with SR equipment.

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

1) FP - Protects/separates and provides structural support of essential equipment required for safe shutdown of the plant.

UFSAR References

2.4.5.7, 6.15.1, 7.3.1.3.1, 7.4.1.4, and 9.2.2 (Unit 1)
3.8.4.1.6, 7.1.1.3, 7.2.2.2.10, and 9.2.2 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-2 lists the component cooling water area 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
Component Cooling Water Area Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Checkered plate Grating Handrails Ladders Platforms Stairs	Structural support
Concrete: columns, foundation, pedestals, roof, shield walls	Fire barrier Flood protection Missile barrier Shelter, protection Structural support
Concrete: columns, roof, shield walls, slabs	Fire barrier Flood protection Missile barrier Shelter, protection Structural support
Concrete: foundation	Structural support
Missile barriers (Unit 1 only)	Shelter, protection Missile barrier
Missile protection doors (Unit 2 only)	Shelter, protection Missile barrier
Structural bolting	Structural support
Structural steel: beams, columns	Structural support

2.4.3 Condensate Polisher Building

Description

The condensate polisher building is designated as Fire Zone 15A and consists of a reinforced concrete building that contains various equipment including Fire Protection equipment and components. The condensate polisher building is described in Unit 1 UFSAR 9.5.1.

Boundary

The condensate polisher building structure boundary includes the exterior surface of the building and all in-scope structural components within the building. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal effort.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

None.

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

1) FP - Although it does not contain any SR or essential equipment, the condensate polisher building is analyzed as Fire Zone 15A.

UFSAR References

9.5.1 (Unit 1)
9.5.1 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-3 lists the condensate polisher building component types that require AMR and their associated component intended functions.

Table 3.5.2-3 provides the results of the AMR.

Table 2.4-3
Condensate Polisher Building Components
Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: foundation	Structural support
Concrete: foundation, roof, slabs, walls	Structural support
Concrete: foundation, walls	Structural support
Concrete: roof, slabs, walls	Structural support
Concrete: roof, walls	Structural support

2.4.4 Condensate Storage Tank Enclosures

Description

The Unit 1 and Unit 2 condensate storage tank enclosures are cylindrical reinforced concrete structures designed to seismic category 1 requirements and are used primarily for tornado missile protection of the tanks.

The Unit 1 condensate storage tank enclosure is an open-roof structure enclosed by steel framing across the top supporting a steel grating security barrier. The structure is supported on a reinforced concrete base mat.

The Unit 2 condensate storage tank enclosure is equipped with a precast concrete dome roof overlaid with reinforced concrete that provides vertical missile protection. The structure is supported on a reinforced concrete base mat.

The steel condensate storage tanks are bolted to reinforced concrete ring wall pedestals that are supported on the base mats. The tank bottoms are supported on Class 1 structural fill that is enclosed within the concrete ring walls.

Boundary

The condensate storage tank enclosures boundary includes the exterior surface of the cylindrical concrete enclosures and all the in-scope structural components within the enclosures. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal effort.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide missile protection for the condensate storage tanks

2) Provide structural support to SR SSCs

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provide structural support NNS components whose failure could prevent satisfactory accomplishment of any of the required safety functions.

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

1) FP - Protects and provides structural support of essential equipment required for safe shutdown of the plant.

2) SBO - Provides structural support and/or shelter to components required for SBO.

UFSAR References

3.5.4.2, 15.2.13, and Appendix 3F, Section 4.3.5 (Unit 1)
3.8.4.1.7 and 15.10 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-4 lists the condensate storage tank enclosure 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
Condensate Storage Tank Enclosure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Checkered plate Grating Handrails Ladders Platforms Stairs	Structural support
Concrete: foundation/ base mat	Structural support
Concrete: foundation/base mat, dome, shield walls, etc.	Fire barrier Missile barrier Shelter, protection Structural support
Concrete: foundation/base mat, ring pedestals	Structural support
Concrete: roof/dome, shield walls (Unit 2 only)	Fire barrier Missile barrier Shelter, protection Structural support
Missile protection hood (Unit 2 only)	Missile barrier
Structural bolting	Structural support
Structural steel	Structural support

2.4.5 Diesel Oil Equipment Enclosures

Description

The Unit 1 diesel oil equipment enclosures consist of complete enclosures for the diesel oil transfer pumps and a partial enclosure for the diesel oil storage tanks. The diesel oil transfer pumps are protected from the environment and external missiles by reinforced concrete seismic category 1 enclosures. The Unit 1 diesel oil storage tanks are located outdoors on concrete foundations surrounded by an overflow/rupture reinforced concrete containment wall.

The Unit 2 diesel oil transfer pumps and diesel oil storage tanks are located within a fully enclosed reinforced concrete seismic category 1 structure. The structure is divided into two distinct compartments by an interior reinforced concrete missile shield wall.

Boundary

The diesel oil equipment enclosures boundary includes the exterior surface of the concrete enclosures and all the in-scope structural components within the enclosures. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal effort.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide missile protection for the diesel oil transfer pumps (Units 1 & 2) and the diesel oil storage tanks (Unit 2 only) Provide structural support to SR SSCs.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provide structural support to NNS components whose failure could prevent satisfactory accomplishment of any of the required safety functions.

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

1) FP - Protects/separates and provides structural support of essential equipment required for safe shutdown of the plant.

2) SBO - Houses and/or supports SBO equipment - Unit 2 only for a Unit 1 SBO.

UFSAR References

9.5.4 (Unit 1)
3.8.4.1.8 and 9.5.4 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-5 lists the diesel oil equipment enclosure 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
Diesel Oil Equipment Enclosure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Checkered plate Grating Handrails Ladders Platforms Stairs	Structural support
Concrete: enclosure foundations	Structural support
Concrete: enclosure foundations, roof, walls	Fire barrier Flood protection Missile barrier Shelter, protection Structural support
Concrete: roof, slabs, walls	Fire barrier Flood protection Missile barrier Shelter, protection Structural support
Diesel oil storage tank foundations	Structural support
Miscellaneous steel (i.e., missile barrier doors) (Unit 2 only)	Fire barrier Structural support
Structural bolting	Structural support

2.4.6 Emergency Diesel Generator Buildings

Description

Both the Unit 1 and the Unit 2 emergency diesel generator buildings are seismic category 1 reinforced concrete structures, housing duplicate diesel generating units, each separated by an interior reinforced concrete wall. Each emergency diesel generator building consists of a base mat, exterior walls, one interior wall separating the units, and a concrete roof. Concrete pedestals on the base mat support the diesel generator sets. The emergency diesel generator buildings also house the components of the diesel generator subsystems, such as the diesel engine and air systems, fuel and lube oil systems, cooling water systems, and the diesel oil system.

Boundary

The emergency diesel generator (EDG) buildings boundary includes the exterior surface of the buildings including appurtenances (stairs, platforms, shield walls, louvers, etc.) and all the in-scope structural components within the building. The EDG buildings boundary has been expanded from the initial PSL license renewal to include the addition of new air diverters and barrier plates at the exterior of the building.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide protection of SR equipment and system components which are inside the buildings from elements of the outside environment (including externally generated missiles).

2) Provide structural support to SR SSCs.

3) Provides protection against the effects of internally generated missiles.

4) Directs flow for adequate air intake and exhaust.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provide structural support to NNS components whose failure could prevent satisfactory accomplishment of any of the required safety functions.

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

1) FP - Protects, separates, and supports essential equipment required for safe shutdown of the plant.

2) SBO - Houses and/or supports SBO equipment.

UFSAR References

3.8.1.1.3, 3.8.1.7.4, 8.3, and 9.4.7 (Unit 1)
3.8.4.1.4, 8.3, and 9.4.5 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-6 lists the emergency diesel generator building 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
Emergency Diesel Generator Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Air exhaust barrier plates structure	Direct flow Structural support
Air intake deflector plate	Direct flow
Air intake diverter structure (roof)	Direct flow
Checkered plate Grating Handrails Ladders Platforms Stairs	Structural support
Concrete air inlet louvers (foundation, slabs, walls)	Direct flow Structural support
Concrete air inlet louvers foundation	Structural support
Concrete: foundation/base mat, walls	Fire barrier Flood protection Missile barrier Shelter, protection Structural support
Concrete: slabs, walls, roofs	Fire barrier Flood protection Missile barrier Shelter, protection Structural support
Concrete: slabs, walls, roofs, trenches	Fire barrier Flood protection Missile barrier Shelter, protection Structural support
Concrete: walls, roofs	Fire barrier Flood protection Missile barrier Shelter, protection Structural support
Exterior louvers (for ventilation and missile protection) (Unit 1 only)	Missile barrier Shelter, protection
Miscellaneous steel	Structural support
Missile protection doors	Flood protection Missile barrier
Missile protection exhaust hoods (Unit 2 only)	Missile barrier Shelter, protection
Structural bolting	Structural support

2.4.7 Fuel Handling Buildings

Description

Each fuel handling building is a seismic category 1 reinforced concrete structure. Each spent fuel pool is a stainless steel lined, reinforced concrete tank structure within the fuel handling building and provides space for the storage of spent fuel, spent fuel casks, and miscellaneous items. The remainder of each fuel handling building consists of concrete exterior walls with reinforced concrete interior walls. The floor and roof for each fuel handling building are of beam and girder construction supported by columns. In addition, the fuel handling building provides an area for cask loading and space for the storage of new fuel and a decontamination area for the spent fuel cask and miscellaneous equipment. Attached to the north outside wall of the fuel handling building, the Cask Handling Facility provides an area where spent fuel casks are prepared for dry storage.

The fuel handling equipment is an integrated system of equipment for refueling the reactor. The system provides for handling and storage of fuel assemblies from receipt of new fuel to shipping of spent fuel. The major fuel handling equipment includes: the reactor cavity seal rings, the manipulator cranes, the fuel transfer system, the spent fuel bridge cranes, and the spent fuel cask crane. The fuel handling equipment is described in Unit 1 UFSAR Section 9.1 and Unit 2 UFSAR Section 9.1. Fuel handling equipment is located in the Containments and the fuel handling buildings. Most of the fuel handling equipment is evaluated in the Overhead Heavy Load Handling Systems commodity.

Boundary

The fuel handling buildings structures boundary includes the exterior surface of the buildings including appurtenances and all the in-scope structural components within the building. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal effort.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide a boundary for SR ventilation (Unit 2 only).

2) Provide structural support for SR systems and equipment located within the building.

3) Provide protection of SR SSCs inside the building from elements of the outside environment (including externally generated missiles and external flooding).

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provide structural support to NNS SSCs, whose failure could result in the loss of a SR function.

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

1) FP - Perform a function that demonstrates compliance with the Commission's regulations for FP.

UFSAR References

3.8.1.1.2, 3.8.1.7.2, and 9.1 (Unit 1)
3.8.4.1.3 and 9.1 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-7 lists the fuel handling building 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
Fuel Handling Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Airtight seals (doors)	Pressure boundary
Boral®	Absorb neutrons
Cask removal L-shape hatch	Shelter, protection Missile barrier
Checkered plate Grating Handrails Ladders Platforms Stairs	Structural support
Concrete: columns, fuel pool and transfer canal walls, roof, slabs, walls	Flood protection Missile barrier Shelter, protection Structural support
Concrete: foundation/base mat	Structural support
Concrete: foundation/base mat, fuel pool and transfer canal walls, walls	Flood protection Missile barrier Shelter, protection Structural support
Concrete: roof, walls	Flood protection Missile barrier Shelter, protection Structural support
Fuel pool gates	Pressure boundary
Fuel upender (passive components)	Structural support
HVAC louver	Structural support

Table 2.4-7
Fuel Handling Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Masonry wall (Unit 1 only)	Structural support
Masonry wall (Unit 2 only)	Shelter, protection Structural support
Metamic® Inserts	Absorb neutrons
Miscellaneous steel (i.e., barriers, frame, frame covers, hatch, missile barriers, radiation shielding, etc.)	Missile barrier Structural support
Pool liner plates	Pressure boundary
Spent fuel pool storage brackets	Structural support
Spent fuel storage racks	Shelter, protection Structural support
Structural bolting	Structural support
Structural bolting/connections	Structural support
Structural steel framing (beams, columns, connections, etc.)	Structural support
Weatherproofing	Shelter, protection

2.4.8 Intake, Discharge, and Emergency Cooling Canals

<u>Description</u>

The intake canal, which takes water directly from the Atlantic Ocean through subaqueous intake water pipes that run under the beach and terminate at the intake canal headwalls, serves as the plant heat sink. In the unlikely event of blockage of the intake canal or pipes, emergency cooling water will be taken from Big Mud Creek through the emergency cooling canal. This emergency source of water is designed to withstand design basis seismic, tornado, and hurricane conditions. Regardless of the source, cooling water is discharged into the discharge canal, and then flows to the Atlantic Ocean through discharge pipes.

The intake and discharge canal headwalls are reinforced concrete structures. The intake canal headwalls provide the termination point for the intake pipes from the Atlantic Ocean. The discharge canal headwalls provide the origination point for the discharge pipes to the Atlantic Ocean.

The emergency cooling canal is seismic category 1 in the area of the intake structure. Erosion protection in the area of the intake structure is provided by a concrete retaining wall and concrete embankments.

<u>Boundary</u>

The evaluation boundary of the cooling canal system on the intake side consists of the intake canal headwalls, the earthen dikes up to the intake structure and the emergency cooling canal between the intake canal and Big Mud Creek. On the discharge side, the discharge canal extends from the seal wells to the two discharge canal headwalls. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal effort.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provides a source of water to Unit I and Unit 2 intake structures, which is used by the ICW system, to achieve and maintain safe shutdown and to mitigate the effects of a LOCA.

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

1) FP - Provides a source of cooling water to the Unit 1 and 2 intake cooling water systems, which is used by the ICW pumps, to provide an adequate heat sink for the CCW system to achieve and maintain hot standby or cold shutdown during plant fires with or without concurrent loss of offsite power.

UFSAR References

2.4.5.7, 2.4.8, 2.4.9, 9.2.7.1, and 9.2.3.2 (Unit 1)
2.4.8, 2.4.9, 3.1.44, 9.2.5 and 10.4.5 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-8 lists the intake, discharge, and emergency cooling canal 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
Intake, Discharge, and Emergency Cooling Canal Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete erosion protection; concrete paving and grout filled fabric	Structural support Emergency cooling water source
Earthen canal dikes	Structural support Emergency cooling water source

2.4.9 Intake Structures

Description

The intake structures are seismic category 1 reinforced concrete structures containing the circulating water pumps and intake cooling water pumps. Each intake structure consists of a base mat, exterior walls braced internally to the bay walls, and an operating deck. Water enters each intake structure through four submerged openings and passes through the stationary and traveling screens before entering the rear of the intake structure, where the pumps are located.

Boundary

The intake structures boundary includes all the structural components that comprise the intake structures. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide structural support and shelter for the intake cooling water pumps and other SR components located within the structures.

2) Provide missile protection for the intake cooling water pumps and other SR components.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provide structural support to NNS SSCs whose loss of structural integrity during an earthquake could result in the loss of a SR function.

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

1) FP - Protects/separates and provides structural support of essential equipment required for safe shutdown of the plant.

UFSAR References

2.4.8, 3.8.1.1.4, 3.8.1.7.3, and Appendix 2G Sections 1.0 and 9.3 (Unit 1)
3.8.4.1.5 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-9 lists the intake structure 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
Intake Structure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: foundation/base mat, pump pedestals, roofs, slabs, walls	Emergency cooling water source Missile barrier Shelter, protection Structural support
Concrete: foundation/base mat, roofs, slabs, walls	Emergency cooling water source Missile barrier Shelter, protection Structural support
Concrete: foundation/base mat, walls	Emergency cooling water source Missile barrier Shelter, protection Structural support
Intake level recorder	Structural support
Miscellaneous steel (i.e., missile barriers, hatch frame covers, etc.)	Missile barrier Shelter, protection Structural support
Retaining walls	Structural support
Structural bolting	Structural support
Structural steel framing (columns, beams, connections)	Missile barrier Shelter, protection Structural support
Weatherproofing	Shelter, protection

2.4.10 Reactor Auxiliary Buildings

Description

The reactor auxiliary buildings are seismic category 1 reinforced concrete structures with concrete exterior walls. The interior floors are beam and girder construction supported by reinforced concrete columns. All interior walls are either solid reinforced concrete block or reinforced concrete. Equipment located in the basement is supported by reinforced concrete piers that are tied to the base mat.

Boundary

The reactor auxiliary buildings Structure boundary includes all the structural components that comprise the reactor auxiliary buildings. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide protection of SR SSCs inside the building from elements of the outside environment (including externally generated missiles and external flooding).

2) Provide structural support for SR systems and equipment located within the building.

3) Provides protection against steam jet effects, which could result from the rupture of high-pressure piping within the building.

4) Provides protection against the effects of flooding in the rooms housing the engineered safeguards systems due to a pipe rupture.

5) Provide radiation protection to the control room for habitability under accident conditions.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provide structural support to NNS SSCs, whose loss of structural integrity during an earthquake could result in the loss of a SR function.

2) Provide shielding against sources of radiation within the building.

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

1) FP - Protects and supports essential equipment required for safe shutdown of the plant.

2) ATWS - Protects and/or supports ATWS equipment.

3) SBO - Protects and/or supports SBO equipment.

UFSAR References

3.8.1.1.1 and 3.8.1.7.1 (Unit 1)
3.8.4.1.2 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-10 lists the reactor auxiliary building 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
Reactor Auxiliary Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Airtight door seals	Pressure boundary
Airtight doors	Structural support Pressure boundary
Checkered plate Grating Handrails Ladders Platforms Stairs	Structural support
Concrete: foundation/base mat	Structural support
Concrete: exterior walls, roofs	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support
Concrete: foundation/base mat, exterior walls	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support
Concrete: roof, slabs, walls	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support
HVAC louvers	Shelter, protection Structural support
Miscellaneous steel (i.e., radiation shielding, missile barriers, hatch frame covers, etc.)	Fire barrier Missile barrier Shelter, protection Structural support
Missile protection doors and barriers	Missile barrier
Reinforced concrete masonry block walls	Fire barrier Pressure boundary Shelter, protection Structural support
Structural bolting	Structural support
Structural steel framing (columns, beams, connections, etc.)	Structural support

Table 2.4-10
Reactor Auxiliary Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Unreinforced concrete masonry block walls	Fire barrier Shelter, protection Structural support
Watertight door seals	Flood protection Pressure boundary
Watertight doors	Flood protection Pressure boundary
Weatherproofing	Shelter, protection

2.4.11 Steam Trestle Areas

<u>Description</u>

Each steam trestle area consists of two braced steel tower structures that contain SR components from the main steam, feedwater and auxiliary feedwater systems. There are two separate trestle compartments per Unit, located between each Unit's containment building and turbine building.

<u>Boundary</u>

The steam trestle area structure boundary includes all the structural components that comprise the steam trestle areas. Electrical duct banks located beneath the steam trestle areas are screened with yard structures. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal.

<u>System Intended Functions</u>

SR functions (10 CFR 54.4(a)(1)):

1) Provide structural support and missile protection for SR systems and equipment located within the structure.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provide structural support to NNS components to preclude interactions with SR equipment.

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

1) FP - Protects, separates, and supports essential equipment required for safe shutdown of the plant.

2) SBO - House, support, and/or protect SBO equipment.

UFSAR References

Appendix 3C (Unit 1)
3.8.4.1.9 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-11 lists the steam trestle area 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
Steam Trestle Area Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Checkered plate Grating Handrails Ladders Platforms Stairs	Structural support
Concrete: foundations	Structural support
Concrete: foundations, slabs	Fire barrier Shelter, protection Structural support
Miscellaneous steel (i.e., missile barriers, steel grating, etc.)	Fire barrier Missile barrier Shelter, protection Structural support
Structural bolting	Structural support
Structural steel framing (columns, beams, connections, etc.)	Structural support Missile barrier

2.4.12 Switchyard

Description

A six bay 230 kV (nominal) switchyard provides switching capability for two main generator outputs, four startup transformers, four outgoing transmission lines (three overhead and one underground), and one distribution substation.

The two outgoing transmission lines identified as midway 1 and 2 terminate at the pull-off towers for switchyard Bays 1A – east and 2 – west. The third transmission line, identified as the Treasure line, terminates at the pull-off towers for switchyard Bay 3 – west. The fourth transmission line, identified as the Turnpike line, terminates at the pull-off towers for switchyard Bay 6 – east. The “Loop” feeds (two lines) for the Hutchinson Island distribution substation are fed from Bay 4 and Bay 6 (one distribution feeder line from each Bay).

The main generators for both Units 1 and 2 produce power at 22 kV which is transformed up to 230 kV nominal and enters the switchyard through overhead lines to the east pull-off tower in Bays I and 3, respectively.

The east pull-off tower in Bay 2 supplies power via over-head lines to startup transformers 1A and 2A, located in the St Lucie Unit 1 transformer yard. The east pull-off tower in Bay 4 supplies power via over-head lines to startup transformers 1B and 2B located in the PSL Unit 2 transformer yard.

Either set of startup transformers can be fed from any one of the incoming transmission lines.

Boundary

The switchyard structure boundary includes all the structural components that comprise the switchyard and switchyard control building. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

None.

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

1) SBO - Provides structural support of essential equipment required for the restoration of offsite power.

UFSAR References

8.2.1 (Unit 1)
8.2.1 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-12 lists the switchyard 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
Switchyard Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete foundations: circuit breakers, control buildings, start-up transformers, transmission towers; covered cable trenches	Shelter, protection Structural support
Concrete: control building walls, foundations, roof, slabs; circuit breakers, start-up transformers, transmission towers	Shelter, protection Structural support
Concrete: control building walls, foundations, roof, slabs; circuit breakers, start-up transformers, transmission towers; covered cable trenches	Shelter, protection Structural support
Masonry block walls (control building)	Shelter, protection Structural support
Structural bolting	Structural support
Transmission towers	Structural support
Weatherproofing (switchyard control building)	Shelter, protection Structural support

2.4.13 Turbine Buildings

Description

The turbine buildings are primarily open steel frame structures, rectangular in shape, and supported by soil supported reinforced concrete foundations. The operating deck and intermediate mezzanine levels are cast-in-place concrete slabs. The turbine generator Units are supported on separate concrete pedestals.

The turbine buildings are not designed to seismic category 1 requirements; however, both turbine buildings were seismically analyzed and found to maintain their structural integrity for the seismic loading condition. The only SR components in the Unit 1 turbine building are two SR valve motors (feedwater isolation valves on the discharge of the feedwater pumps) and associated SR power. There are no SR components in the Unit 2 turbine building. Both turbine buildings have SR piping buried beneath the ground floor slab.

Boundary

The turbine buildings boundary includes all the structural components that comprise the turbine buildings. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide structural support to SR components.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Maintain structural support of the overall building structure to preclude seismic interaction with the Category I piping and electrical duct banks which are buried in sand fill beneath the ground floor slab of the building or interaction with the adjacent steam trestle areas.

2) Provide structural support for SR systems and components located within the structure. (Main Feedwater Pump Discharge Isolation valve associated components - Unit 1 only).

3) Provide structural support to NNS components to preclude interactions with SR equipment. (Unit 1 only)

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

1) FP - Protects, separates, and supports essential equipment required for safe shutdown of the plant.

2) ATWS - House and/or support ATWS equipment.

3) SBO - House and/or support SBO equipment.

UFSAR References

3.8.4.1 (Unit 1)
3.8.4.1.12 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-13 lists the turbine building 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
Turbine Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete curbs (Unit 2, 2B Switchgear Room)	Fire protection
Concrete: foundation/base mat	Structural support
Concrete: slabs	Structural support
Structural bolting	Structural support
Structural steel framing (columns, beams, connections, etc.)	Structural support
Turbine generator casings (covers)	Missile barrier
Unreinforced concrete masonry block walls (Switchgear rooms)	Structural support
Weatherproofing	Shelter, protection

2.4.14 Ultimate Heat Sink Dam (Barrier Wall)

Description

The ultimate heat sink dam is a seismic category 1 reinforced concrete barrier wall that extends across the emergency cooling canal. The main structure of the ultimate heat sink dam consists of the concrete barrier wall, the perpendicular concrete buttresses, the concrete mat foundation, and the equipment rooms. The function of the ultimate heat sink dam is to separate the waters of Big Mud Creek from the intake canal during normal operation, and to provide a SR source of cooling water in the unlikely event that the ocean intake becomes unavailable.

Boundary

The ultimate heat sink dam is a reinforced concrete buttressed barrier wall which extends across the emergency cooling canal connecting Big Mud Creek to the intake canal. The ultimate heat sink dam evaluation boundary is at the exterior surface of the structure. The adjacent hurricane protection sheet piles are also considered within the evaluation boundary. The concrete compaction piles located in the underlying soil are design features of the soil, and thus do not require screening as unique components. There are no significant differences between the current boundaries and those identified as part of the original PSL license renewal.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide structural support for SR systems and equipment located within the structure.

2) Furthermore, the equipment room and barrier wall provide missile protection for the SR components.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) The UHS dam contains both SR and NNS components. Accordingly, the dam must provide support to NNS components to preclude adverse interactions with SR functions.

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

None.

UFSAR References

2.3.3.5, 3.8.1.1.5, 3.8.1.7.5, 9.2.7, and Appendix 2G (Unit 1)
9.2.5 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-14 lists the ultimate heat sink dam (barrier wall) 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
Ultimate Heat Sink Dam (Barrier Wall)
Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Checkered plate Grating Handrails Ladders Platforms Stairs	Structural support
Concrete: foundation	Structural support
Concrete: foundations, roof, slabs, walls	Missile barrier Shelter, protection Structural support
Miscellaneous steel (i.e., missile barriers, hatch covers, etc.)	Shelter, protection Missile barrier
Steel sheet piling (beneath dam)	Shelter, protection
Structural bolting	Structural support

2.4.15 Yard Structures

Description

Yard structures includes concrete foundations, concrete pipe trenches, concrete duct banks, electrical manholes, and the discharge canal nose wave protection. Steel support structures associated with these concrete structures are also included.

Boundary

The evaluation boundary of each yard structure is the exterior surface of the structure. For trenches and duct banks, the structure boundary shall terminate at the point it enters a separate structure (e.g., building or manhole).

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide structural support to SR components.

2) Provide shelter/protection to SR components.

3) Provide missile protection to SR components.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provide structural support to NNS components whose failure could prevent satisfactory accomplishment of any required SR functions.

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

1) FP - Provide structural support to equipment relied upon to meet FP requirements.

2) SBO - Provide structural support for SBO equipment.

UFSAR References

2.4.5.7, 8.3.1.1.9, 8.3.1.2, and 8.3.2.2 (Unit 1)
2.4.5.3.2 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-15 lists the yard structure 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
Yard Structure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete missile shield for diesel oil pipe	Missile barrier
Discharge canal nose wave protection (concrete cap)	Flood protection
Discharge canal nose wave protection (sheet piling)	Flood protection
Electrical duct banks and manholes	Shelter, protection Structural support
Foundations	Structural support
Reinforced concrete pipe trenches	Shelter, protection Structural support
Steel missile shield for diesel oil pipe (Unit 2 only)	Missile barrier
Structural bolting	Structural support
Transmission towers	Structural support
Weatherproofing	Shelter, protection

2.4.16 Component Support Commodity

Description

The component support commodity comprises 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 includes the grout under the baseplate and fasteners (e.g., bolts, studs, nuts) used with the support or equipment anchorage / embedment.

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). Types of equipment and component supports evaluated as part of this commodity include:

a. 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.

b. 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.

c. Pipe Supports – Includes all items used to support piping. The support boundary includes all the auxiliary steel back to the structure's surface.

d. Pipe Restraints – Failure and seismic restraints that limit pipe movement during postulated events. Includes structural steel and fasteners.

e. Equipment Supports – Includes structural steel, fasteners, and vibration mounts that secure equipment to structures.

f. HVAC Duct Supports – Includes structural steel and fasteners that support/attach ventilation duct to structures.

Boundary

The component supports boundary includes all the structural components that comprise the Component Supports Commodity.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide structural support for SR SSCs.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provide structural support for NNS SSCs whose failure could prevent satisfactory accomplishment of station blackout, FP, or SR functions.

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

1) FP - Provide support for SSCs that are relied upon in safety analyses and plant evaluations to support site's implementation of FP regulations.

2) ATWS - Provide support for SSCs that are relied upon in safety analyses and plant evaluations to support site's implementation of ATWS regulations.

3) SBO - Provide support for SSC that are relied upon in safety analyses and plant evaluations to support the site's coping with a SBO.

UFSAR References

1.2 (Unit 1)
1.2 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-16 lists the component support commodity structural component types that require AMR and their associated component intended functions.

Table 3.5.2-16 provides the results of the AMR.

Table 2.4-16
Component Support Commodity Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage / Embedment	Structural support
ASME class 1 structural bolting	Structural support
ASME class 1 (non-RCS) pipe supports and component supports	Structural support
ASME class 2 and 3 structural bolting	Structural support
ASME class 2 and class 3 pipe supports and component supports	Structural support
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support
Component supports (NNS)	Structural support
Conduits and cable trays	Structural support Shelter, protection
Conduits (non-metallic)	Structural support Shelter, protection
Constant and variable load spring hangers; guides; stops	Structural support
Electrical and instrument panel and enclosure supports	Structural support
Electrical and instrument panels and enclosures	Structural support Shelter, protection
Non-metallic thermal insulation	Insulate (thermal)
Pipe whip restraints	Pipe whip restraint
Sliding support surfaces (Unit 1 CCW heat exchangers)	Structural support
Sliding support surfaces (Unit 2 CCW heat exchangers)	Structural support
Structural bolting	Structural support
Vibration isolation elements	Structural support

2.4.17 Fire Rated Assemblies

Description

Fire rated assemblies include fire barriers, fire doors, fire dampers, and penetration seals. The fire rated assemblies are described in Section 9.5.1 of the Unit 1 and Unit 2 UFSARs.

Fire barriers are provided to ensure that the function of one train of redundant equipment necessary to achieve and maintain safe shutdown conditions remains free of fire damage. Fire barriers provide a means of limiting fire travel by compartmentalization and containment. PSL Units 1 and 2 fire barriers include walls, floors, ceilings, radiant energy shields, flame impingement shields, conduit fire wrap, and conduit plugs. Wall type barriers and shields include concrete and masonry walls. Fire-resistant panels (e.g., Thermo-lag, sheet metal/ceramic fiber) mounted on steel framing are also used as fire barriers. Concrete and masonry walls, floors, and ceilings are evaluated with the specific structure in which they reside.

Fire door assemblies prevent the spread of fire through fire barrier passageways.

Fire dampers are provided to prevent the spread of fire through ventilation penetrations. Fire dampers are evaluated with Ventilation in Subsection 2.3.3.15.

Penetration seals are provided to maintain the integrity of fire barriers at barrier penetrations. The types of materials used for the various penetrations range from silicone gels for piping and heating, ventilation, and air conditioning (HVAC) penetrations to grouts for conduit and plumbing. Cable tray penetrations are sealed with Marinite board, ceramic fiber filler material, and a protective fire-retardant cable coating.

Boundary

The evaluation boundary for fire rated assemblies is the external surface of that assembly. The fire area boundaries (walls, ceilings, and floors) define the NFPA 805 Areas. Concrete and masonry fire barriers (i.e., walls) are screened with the structure in which they reside.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Airtight fire doors and fire barrier penetration seals associated with SR ventilation system boundaries (e.g., control room air conditioning, ECCS area ventilation, etc.) and watertight fire doors associated with flood protection are NNS fire rated assemblies which could affect SR functions.

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

1) FP - Relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for FP. Generally, the FP System protects plant equipment in the event of a fire to ensure safe plant shutdown and minimize the risk of a radioactive release to the environment. Fire assemblies with an intended function of providing pressure boundary for this commodity group are for halon in the cable spreading room.

UFSAR References

Unit 1

6.4.1 and 9.5.1 (Unit 1)
6.4.5 and 9.5.1 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-17 lists the fire rated assembly component types that require AMR and their associated component intended functions.

Table 3.5.2-17 provides the results of the AMR.

Table 2.4-17
Fire Rated Assemblies Subject to Aging Management Review

Component Type	Component Intended Function(s)
Conduit caps	Fire barrier Pressure boundary
Conduit plugs	Fire barrier
Fire damper housings	Fire barrier
Fire doors - airtight	Fire barrier Pressure boundary
Fire doors - watertight	Fire barrier Flood barrier
Fire doors (NFPA 805 barriers)	Fire barrier Pressure boundary
Fire wrap (conduit and steel supports)	Fire barrier
Fire sealed isolation joint	Fire barrier
Fire seals – cable tray penetrations	Fire barrier Pressure boundary
Fire seals – mechanical penetrations	Fire barrier Pressure boundary
Fire wrap (conduit and steel supports)	Fire barrier
Flame impingement shields (insulating blankets for cable trays)	Fire barrier
Miscellaneous fire barriers	Fire barrier Pressure boundary
Radiant energy shields	Fire barrier

2.4.18 Overhead Heavy Load Handling Systems

Description

The Overhead Heavy Load Handling Systems in the scope of Subsequent License Renewal include NUREG-0612 overhead cranes which must be capable of sustaining their rated loads during the subsequent period of extended operation. The PSL Unit 1 NUREG 0612 cranes are listed in Unit 1 UFSAR Section 9.6.2 and include the Reactor Building Polar Crane, the Intake Structure Bridge Crane, the Spent Fuel Cask Handling Crane, the Auxiliary Telescoping Jib Crane, the Refueling Machine 1-ton hoist, the Fuel Pool Bulkhead Monorail, the Turbine Building Gantry Crane. The PSL Unit 2 NUREG-0612 cranes are listed in Unit 2 UFSAR Table 9.6-1 and include Charging Pump A, B, and C Trolley Hoists, Turbine Gantry Crane, Reactor Polar Crane, Auxiliary Telescoping Jib Crane, Refueling Machine/Hoist, Spent Fuel Handling Machine, Refueling Canal Bulkhead Monorail, Cask Storage Pool Bulkhead Monorail, Spent Fuel Cask Handling Crane, Diesel Generator Monorails, and Intake Structure Bridge Crane.

Additionally, some non-NUREG-0612 overhead load handling devices are in the scope of subsequent license renewal since their failure in a seismic event could impact SR systems, structures, and components. For Unit 1 these include: the Unit 1 Emergency Diesel Generator Trolley Hoists, Emergency Diesel Generator A and B Turbo Charger Trolley Hoists, FHB Fuel Pool Pump Trolley Hoists, Fuel Reconstitution Trolley, FHB Jib Crane, Spent Fuel Handling Machine, FHB Sump Pump Jib Crane, Cask Storage Pool Bulkhead Trolley Hoist, RAB Control Element Assembly MG Drive Trolleys, Charging Pump A, B, and C Trolley Hoists, RAB Pump Room A and B Trolley Hoists, RAB Purification Filter Hoist, RAB Switchgear Room Trolley Hoists, RCB Jib Crane, RCB Vacuum Relief Valve Trolley Hoists, RCB Maintenance Hatch Equipment Hoists, RCB Personnel Entrance Hoists. For Unit 2 these include: CCW Pump Trolley Hoist, FHB Fuel Pool Pump Trolley Hoists, FHB Fuel Reconstitution Trolley, FHB Jib Crane, FHB Sump Pump Jib Crane, RAB Control Element Assembly MG Drive Trolleys, RAB Pump Room A and B Trolley, RAB Purification Filter Hoist, RAB Switchgear Room Trolley Hoists, RCB Jib Crane, RCB Vacuum Relief Valve Trolley Hoists, RCB Maintenance Hatch Equipment Hoists, RCB Personnel Entrance Hoists.

The portions of these load handling systems within the scope of SLR requiring AMR are the passive structural elements including bridge girders and beams, trolley girders and beams, bolted and welded connections, crane rails, and other related structural components. In addition, the mounting of auxiliary equipment on the cranes is included to preclude seismic interactions. Information on cranes and overhead heavy load handling systems can be found in Section 9.6 of the Unit 1 and Unit 2 UFSARs.

Boundary

The Overhead Heavy Load Handling Systems boundary includes all the structural components that comprise the Overhead Heavy Load Handling Systems. The boundary is limited to the load-bearing components that structurally support the heavy loads in a passive manner. This includes the foundation and bridge and trolley items such as structural beams, girders, and rails.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

1) Provide structural support to SR components.

NNS components that could affect SR functions (10 CFR 54.4(a)(2)):

1) Provide structural support to NNS components whose failure could prevent satisfactory accomplishment of any of the required SR functions.

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

None.

UFSAR References

9.6.2 (Unit 1)
Table 9.6-1 (Unit 2)

Subsequent License Renewal Drawing

None.

Components Subject to AMR

Table 2.4-18 lists the Overhead Heavy Load Handling Systems component types that require AMR and their associated component intended functions.

Table 3.5.2-18 provides the results of the AMR.

Table 2.4-18
Overhead Heavy Load Handling System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: foundations	Structural support
Crane bridges	Structural support
Crane rails	Structural support
Rail hardware	Structural support
Structural bolting	Structural support
Structural bolting (Non-NUREG-0612)	Structural support
Structural members	Structural support
Structural members (Non-NUREG-0612)	Structural support

2.5 SCOPING AND SCREENING RESULTS: ELECTRICAL AND INSTRUMENTATION & 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 PSL 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 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 as a whole was screened (for LR aging management inclusion), but not the internal parts of the breaker (of course, breakers are screened out for aging management as active components).

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 PSL 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 and I&C components and commodity groups, the criterion of 10 CFR 54.21(a)(1)(i) is applied to identify electrical and I&C commodity groups that perform their functions without moving parts or without a change in configuration or properties. The following electrical and I&C commodity groups meet the screening criteria of 10 CFR 54.21(a)(1)(i) for PSL:

- Electrical Penetration Assemblies
- Insulated cables and connections
- 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 St. Lucie

The following electrical and I&C commodity groups are not applicable to PSL:

<u>Cable Tie-Wraps</u>

At PSL, 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>Fuse Holders</u>

The cables and connections commodity group includes fuse holders (fuse blocks). Consistent with NUREG-2191, Sect. 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, circuit boards, and other electrical enclosures with active electrical components 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 the initial License Renewal, PSL determined aging management of fuse holders would be required for those cases where fuse holders are not considered subcomponent parts of a larger assembly. PSL identified sets of fuses in the switchgear rooms / cable spreading rooms which were not subcomponents of other enclosures or active components. The staff, in its review of the initial LRA, questioned the PSL position that the fuse holders identified as in-scope (in stand-alone electrical boxes) were not subject to aging management review (AMR). This issue was covered in Section 3.6.2.1.4 of NUREG-1779 (the NRC Safety Evaluation Review of the initial PSL LRA), under Open Item 3.6.2.1-1, which contained the following discussion/resolution:

> OE, as discussed in NUREG-1760, "Aging Assessment of Safety-Related Fuses Used in Low-and Medium-Voltage Applications in Nuclear Power Plants," identified that aging stressors such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, or oxidation of the connections surfaces can result in fuse holder failure. On this basis, fuse holders, including both the insulation material and the metallic clamps, are subject to both an AMR and AMP for license renewal. Typical plant effects observed from fuse holder failure due to aging have resulted in challenges to safety systems, cable insulation failure due to over-temperature, failure of the containment spray pump to start, a reactor trip, etc. Therefore, managing age-related failure of fuse holders would have a positive effect on the safety performance of a plant. Information Notices 91-78, 87-42, and 86-87 are examples that underscore the safety significance of fuse holder and the potential problems that can arise from age-related fuse holder failure. Open Item 3.6.2.1-1 was related to the aging effects identified in ISG-5 on the identification and treatment of electrical fuse holders for license renewal. The fuse holders include both the insulation material and metallic clamps. The EQ cables and connections AMP [XI.E1] will manage the aging of insulation material but not the metallic portions. In the ISG, the staff indicates that the AMR for fuse holders (metallic clamps) needs to include the following stressors (if applicable - fatigue, mechanical stress, vibration, chemical contamination, and corrosion. Where environments or operating conditions preclude such aging effects (e.g., fuse holders not subject to vibration from rotating machinery), they need not be addressed by the AMP. The applicant states that the only fuse holders that were not part of large, active assembly are those installed to provide double isolation for NNS loads powered from SR power supplies. The applicant addressed each aging effect identified in the ISG and provided technical justification of why an AMP for the metallic portions of these fuse holders is not required. The staff agreed with the applicant's determination that the environments and/or operating conditions of the fuse holders preclude the aging effects identified in ISG-5. The staff finds that an-AMP for the metallic portions of fuse holders is not required. The applicant also reviewed IN 86-87, 87-42, and 91-78 to see if the aging effects identified in the INs were applicable to the fuse holders at PSL. The applicant concluded, and the staff concurred, that the above INs are not applicable to the fuse holders at PSL because of differences in usage, design, and construction. The staff, therefore, found the applicant's response to the open item acceptable. The staff considers Open Item 3.6.2.1-1 closed.

The PSL plant design basis was reviewed to determine that the population of fuses (those not part of a larger assembly) within the scope of SLR had not changed since the approval of the initial LR application. In addition, the PSL transition to the NFPA-805 standard for Fire Protection was reviewed to determine if any new fuses (those not part of a larger assembly) were now considered within the scope of the initial LR evaluation. A plant modification was identified in 2020 (for Unit 2 only) which added a junction box in the 6.9 kV switchgear room (for 125 VDC control power circuits) that contains only fuses and wiring. This fuse box is in a controlled (benign) environment, the fuses are not manipulated, and the fuses are not subject to electrical stress (high cycling or high heating). There are no relevant aging mechanisms or aging effects for these fuse holders, relative to the insulating material, the metallic clamps, or the box itself (i.e., there are no stressors to cause corrosion or degradation).

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 and I&C 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 Environmental Qualification Program. This is because electrical and I&C components (with replacement schedules) and commodities included in the Environmental Qualification 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 Environmental Qualification 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 Environmental Qualification Program are discussed in Section 4.4.

<u>Insulated Cables and Connections</u>

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 Environmental Qualification Program. The insulated cables and connections that are included in this program have a qualified life that is documented in the Environmental Qualification Program. Components in the Environmental Qualification Program are replaced prior to the expiration of their qualified life. Accordingly, all insulated cables and connections within the Environmental Qualification 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 Environmental Qualification 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 Environmental Qualification 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 the NRC letter dated April 1, 2002 (Reference ML020920464). An evaluation was performed of the restoration power path for offsite power following an SBO event based on the guidance of the NRC letter. Consistent with this evaluation, 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 Environmental Qualification 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 PSL 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 Figure 2.5-1.

Electrical and I&C Penetration Assemblies

All of the electrical/I&C penetration assemblies in the scope of license renewal are included in the PSL Environmental Qualification Program. As such, these components have a qualified life that is described in program documents and, per 10 CFR 54.21(a)(1)(ii), they are not subject to an aging management review.

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 PSL and the iso-phase bus does not perform or support a SLR intended function. Only non-segregated MEB in the 4.16 kV electrical system performs an SLR intended function and none of this MEB is in the Environmental Qualification Program. Therefore, non-segregated MEB in the 4.16 kV electrical system meets the criterion of 10 CFR 54.21(a)(1)(ii) and is subject to an AMR. Note that the non-segregated MEB at PSL (including that portion within the scope of SLRA) is in the process of being replaced by cable bus. Once this plant change is complete, there will be no MEB within the SLRA scope (the cable bus will perform the SLR intended function).

Cable Bus

Cable bus is a variation on 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 typically has louvers (or openings, such as slots) in the ductwork and is routed above ground like metal enclosed bus.

The cable bus that is within the scope of SLR is not included in the Environmental Qualification Program, and therefore meets the criterion of 10 CFR 54.21(a)(ii) and is 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 from the electrical operating circuits and are not required for those circuits or equipment to perform their intended functions. Uninsulated ground conductors are credited at PSL with providing a fire protection function for buildings (through lightning protection). Therefore, the uninsulated ground conductors at PSL are within the scope of SLR.

2.5.2 Electrical and I&C Components and Commodity Groups Subject to Aging Management Review

Table 2.5-2 lists the electrical and I&C components and commodity groups that require AMR and their associated component intended functions.

Table 3.6.2-1 provides the results of the AMR.

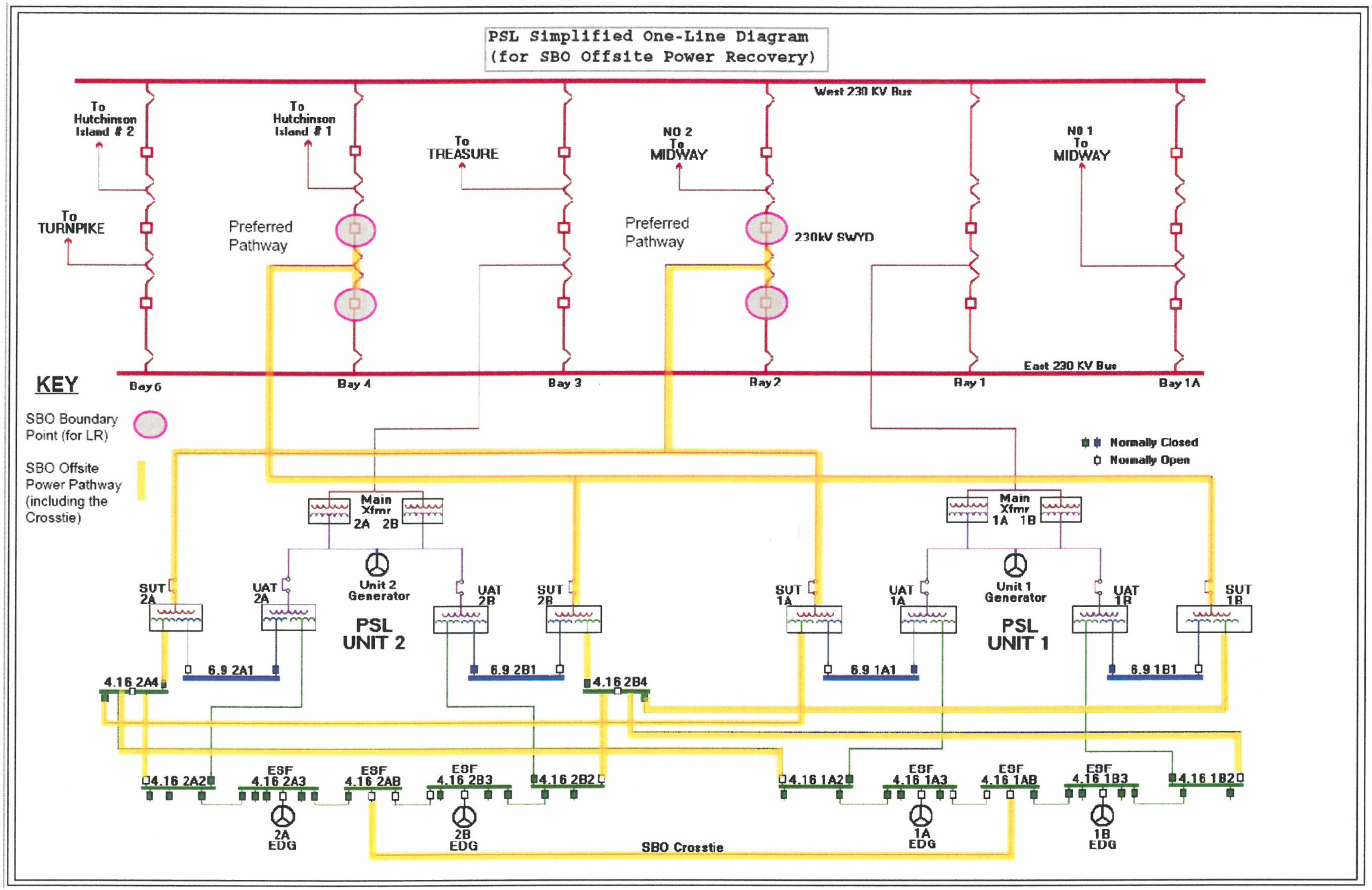
Table 2.5-1
Electrical and I&C Component Commodity Groups Installed at PSL for In-Scope Systems

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
Cable Bus	Fuse Holders		
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 (Metal Enclosed Bus)	Indicators	Recorders	Thermocouples
	Insulated 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 I&C System Commodities Subject to Aging Management Review

Component/ Commodities	Component Intended Function(s)
Insulated cables and connections	Electrical continuity
Metal enclosed bus - conductors Metal enclosed bus - insulators (sections used for SBO offsite power recovery)	Electrical continuity Insulate (electrical)
Cable bus – insulated cables (sections used for SBO offsite power 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
Uninsulated ground conductors	Electrical continuity (for lightning / fire protection)

Figure 2.5-1
PSL Simplified One-Line Diagram (For SBO Offsite Power Recovery)



3.0 AGING MANAGEMENT REVIEW RESULTS

This chapter provides the results of the Aging Management Review (AMR) for those systems and structures in the scope of subsequent license renewal (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 Vessels, 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 PSL 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 Vessels, 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 Vessels, 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 AMP 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 AMP 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
- AMPs
- 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 AMPs used to manage the aging effects requiring management are listed in the sixth column of Table 2. AMPs are described in Appendix B.

NUREG-2191 Item - Each combination of component type, material, environment, aging effect requiring management, and AMP 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 AMP 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, AMPs 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 AMP 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 AMP 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 be wetted, but only rarely; equipment surfaces are normally dry.	Air – indoor uncontrolled
Air – outdoor	The outdoor environment consists of atmospheric air, salt-laden air, ambient temperature and humidity, and exposure to precipitation.	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	Air and condensation on surfaces of indoor systems with temperatures below dew point; condensation is considered untreated water due to potential for surface contamination.	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
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

Table 3.0-1
Mechanical System Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
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
Reactor coolant and neutron flux	The reactor core environment that will result in a neutron fluence exceeding 1017 n/cm2 (E >1 MeV) at the end of the license renewal term.	Reactor coolant and neutron flux
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	Any indoor or outdoor air environment where the cited aging effects could occur regardless of the particular air environment (e.g., air-indoor uncontrolled, air-outdoor).	Air
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. The potential for leakage from bolted connections (e.g., flanges, packing) impacting in-scope components exists in this environment.	Air – indoor uncontrolled
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	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
Groundwater/soil	Groundwater is subsurface water that can be detected in wells, tunnels, or drainage galleries, or that flows naturally to the earth's surface via seeps or springs. Soil is a mixture of organic and inorganic materials produced by the weathering of rock and clay minerals or the decomposition of vegetation. Voids containing air and moisture can occupy 30–60% of the soil volume. Concrete subjected to a groundwater/soil environment can be vulnerable to an increase in porosity and permeability, cracking, loss of material (spalling, scaling), or aggressive chemical attack. Other materials with prolonged exposures to groundwater or moist soils are subject to the same aging effects as those systems and components exposed to raw water.	Groundwater/soil

Table 3.0-2
Structural Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
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
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
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

Table 3.0-3
Electrical 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. 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).	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 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	The environment is similar to the Air-indoor uncontrolled environment but is used for environments 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
Adverse localized environments	An adverse localized environment (ALE) is an environment limited to the immediate vicinity of a component that is hostile to the component material, thereby leading to potential aging effects. Electrical insulation used for electrical cables can be subjected to an ALE. ALEs can be due to any of the following: (1) exposure to significant moisture, or (2) exposure to heat, radiation, or moisture and are represented by specific GALL-SLR AMR items. Note that significant moisture is a wet environment for cable or connection insulation materials where the moisture lasts more than a few days (e.g., cable submerged in standing water).	Adverse localized environment caused by heat, radiation, or 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 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 Vessels (2.3.1.1)
- Reactor Vessel Internals (2.3.1.2)
- Pressurizer (2.3.1.3)
- Reactor Coolant 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 Vessels – 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 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 Vessels

Materials

The materials of construction for the reactor vessel components are:

- Carbon steel
- Carbon steel with stainless steel cladding
- 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 vessels 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 Reactor Coolant Pressure Boundary 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

Materials

The materials of construction for the reactor vessel internals components are:

- Nickel alloy
- Stainless steel

Environments

The reactor vessel internals components are exposed to the following environments:

- Reactor coolant
- Neutron flux

Aging Effects Requiring Management

The following aging effects associated with the reactor vessel internals require management:

- Changes in dimension
- 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 vessel internals components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)
- Reactor Vessel Internals (B.2.3.7)
- Water Chemistry (B.2.3.2)

3.1.2.1.3 Pressurizers

Materials

The materials of construction for the pressurizer components are:

- Carbon steel
- Carbon steel with nickel alloy cladding
- Carbon steel with stainless steel cladding
- CASS
- Nickel alloy
- 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 fracture toughness

- 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)
- 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)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B.2.3.6)
- Water Chemistry (B.2.3.2)

3.1.2.1.4 Reactor Coolant Piping

Materials

The materials of construction for the reactor coolant piping components are:

- Carbon steel
- Carbon steel with stainless steel cladding
- CASS
- Nickel alloy
- Stainless steel
- Steel

Environments

The reactor coolant piping components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Reactor coolant
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the reactor coolant 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 piping components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)
- ASME Code Class 1 Small-Bore Piping (B.2.3.22)
- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- Closed Treated Water Systems (B.2.3.12)
- 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)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Pressurizer Surge Line (B.2.3.44)
- 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 cladding
- Carbon steel with stainless steel cladding
- Nickel alloy
- Stainless steel
- 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 > 140ºF

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 Reactor Coolant Pressure Boundary Components (B.2.3.5)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.8)
- 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 system components is an aging effect evaluated as a TLAA in Section 4.3.1, "Metal Fatigue of Class 1 Components" and Section 4.3.2, "Metal Fatigue of Non-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).

Not applicable. This further evaluation item is only applicable to Westinghouse Model 44 and 51 steam generators.

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.

Not applicable. This further evaluation item is only applicable to Westinghouse Model 44 and 51 steam generators.

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/cm^2 (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 TLAA. The TLAA evaluation of neutron irradiation embrittlement is discussed in Section 4.2, "Reactor Vessel Neutron Embrittlement Analysis."

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, lower and intermediate 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 AMP, which is addressed in Section B.2.2.2. This AMP is consistent with 10 CFR Appendix H. 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. 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.

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 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking

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 Crack Growth Due to Cyclic Loading

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 XI2. 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).

Based on review of the fabrication weld procedures and weld inspection records for internal cladding, St. Lucie Units 1 and 2 RPVs are not susceptible to underclad reheat cracking nor underclad cold cracking because the vessel manufacturer did not use high-heat-input welding processes and heat treating practices that contributed to the cracking conditions. Specifically, the procedures indicate that the St. Lucie reactor vessels were clad using lower-heat-input one-wire and two-wire submerged or shielded metal arc cladding processes with which reheat cracking was found by testing not to occur. Furthermore, preheating and post-heating were applied on all layers of multiple layers of cladding so that cold cracking is also precluded. Additionally, the replacement reactor vessel closure head (RVCH) forgings for both Units are SA-508 Class 3 components which are not susceptible to crack growth due to cyclic loading.

Thus, underclad cracking of the PSL RPVs and replacement heads is not an applicable aging mechanism.

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 PSL reactor vessels are a CE design which does not include bottom-mounted instrument guide tubes and as such this further evaluation item is not applicable.

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 PSL. 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 PSL Class 1 CASS piping and piping components is demonstrated in the OE discussion in Section B.2.3.6. Therefore, the Water Chemistry (B.2.3.2) AMP 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 PSL 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 PSL 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 0-ring. Additionally, OE was reviewed for the last 10 years and no ARs have been generated in regard to cracking of RPV flanges. Since the leak detection lines are NNS and their potential failure would not prevent satisfactory accomplishment of any SR 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 Aging Management Review (AMR) is not required. This position is documented through

PSLs response to RAI 2.3.1-3 regarding the issue during initial license renewal (Reference ML022810608).

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 PSL as feedwater impingement plates are not an applicable component type for the steam generators installed at PSL Units 1 and 2.

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)" (Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML12017A191 through ML12017A197 and ML12017A199), provided the industry's initial set of aging management inspection and evaluation (I&E) recommendations for the reactor vessel internal (RVI) components that are included in the design of a PWR facility. Since the issuance of MRP-227-A on January 9, 2012, EPRI updated its I&E guidelines for the PWR RVI components in Topical Report No. 3002017168, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A)" (Reference ML20175A112). MRP-227, Revision 1-A, incorporated the industry's bases for resolving operating experience and industry lessons learned resulting from component-specific inspections performed since the issuance of MRP-227-A in January 2012. The staff found the guidelines in MRP-227, Revision 1-A, acceptable, as documented in a staff-issued safety evaluation dated April 25, 2019 (Reference ML19081A001) and approved the topical report for use as documented in the staff's letters to the EPRI Materials Reliability Program (MRP) dated February 19, 2020 and July 7, 2020 (ADAMS Accession Nos. ML20006D152 and ML20175A149).

In MRP-227, Revision 1-A, the EPRI MRP identified that the following aging mechanisms may be applicable to the design of the RVI components in these types of facilities: (a) stress corrosion cracking (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 component distortion, and (h) thermal or irradiation-enhanced stress relaxation or irradiation enhanced creep.

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 the applicable inspection categories (as evaluated in MRP-227, Revision 1-A) were 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's assessment in MRP-227, Revision 1-A, did not evaluate whether operation of Westinghouse-designed, B&W-designed and CE-designed reactors during an SLR operating period (60 to 80 years) would have any impact on the existing susceptibility rankings and inspection categorizations for the RVI components in these designs, as defined in MRP-227, Revision 1-A or the applicable MRP background documents (e.g., MRP-191, Revision 1, for Westinghouse-designed or CE-designed RVI components or MRP-189, Revision 2, for B&W-designed components).

As described in GALL-SLR Report AMP XI.M16A, the applicant may use the MRP-227, Revision 1-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, Revision 1-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 changes to the MRP-227, Revision 1-A based program that are 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. If a gap analysis is needed to establish the appropriate aging management criteria for the RVI components, the applicant has the option of including the gap analysis in the SLRA or making the gap analysis and any supporting gap analysis documents available in the in-office audit portal for the SLRA review.

Subsequent license renewal (SLR) applicants for Units of a PWR design will no longer need to include separate SLRA Appendix C section responses in resolution of the A/LAIs previously issued on MRP-227-A because the A/LAIs were resolved and closed by the staff in the April 25, 2019, safety evaluation for MRP-227, Revision 1-A. The sole A/LAI issued by the staff in the safety evaluation dated April 25, 2019, relates to an applicant's methods and timing of inspections that will be applied to the baffle-to-former bolts or core shroud bolts in the plant design. Since an applicant's resolution of this A/LAI can be appropriately addressed in the "Operating Experience" program element *discussion for the AMP and in the applicant's basis document for the AMP, a separate SLRA Appendix C response for the A/LAI is unnecessary.*

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. If the AMP is a plant-specific program, 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 PSL Reactor Vessel Internals AMP is based on the current MRP-227 Revision 1-A framework, as endorsed by SLR-ISG-2021-01-PWRVI (Reference ML20217L203) and 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 AMP, the PSL 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 <u>Loss of Material Due to Wear</u>

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 industry OE described was associated with a Westinghouse-designed reactor vessel head. The original PSL reactor vessel heads were designed by Combustion Engineering (CE). The PSL replacement reactor vessel closure heads were designed and fabricated by Framatome based on the original CE head design. The

PSL control element drive mechanisms do not experience the wear issue described in the industry OE.

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 industry OE described was associated with a Westinghouse-designed reactor vessel head. The original PSL reactor vessel heads were designed by Combustion Engineering (CE). The PSL reactor vessel closure heads were designed and fabricated by Framatome based on the original CE head design. The PSL control element drive mechanisms do not experience the wear issue described in the industry OE.

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 (Reference 1.6.14).*

   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.

The PSL Unit 1 divider plate assemblies use a floating divider plate and as such there is no crack initiation point. A plant-specific AMP is not necessary-

The PSL Unit 2 steam generators have an Alloy 690 divider plate and Alloy 690 type weld materials. As such, a plant-specific AMP is not necessary.

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.

PSL Unit 1 has thermally treated Alloy 690 SG tubes with tubesheet cladding using Alloy 600 type material. Accordingly, PSL evaluated the tubesheet for susceptibility to crack initiation and found that the minimum chromium content in the welds is 24.2 percent and the tubesheet primary face is in compression. As such, a plant-specific AMP is not necessary.

The PSL Unit 2 steam generators have 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 SS or steel piping or piping components within the scope of subsequent license renewal that are exposed to concrete at PSL. 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 PSL OE confirms halides are potentially present in both the indoor and outdoor environments at PSL. As such, all SS components exposed to an air-indoor uncontrolled environment in the RCS 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. Conditions 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 B.1.3, 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 OE process and acceptance criteria are described in Appendix B.1.4, Operating Experience.

3.1.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Reactor Vessels, 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 Vessels, 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 AMPs selected to manage aging effects for the Reactor Vessels, Internals, and Reactor Coolant system components are identified in the summaries in Section 3.1.2 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 subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Reactor Vessels, 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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / 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 and studs exposed to air-indoor uncontrolled is addressed as a TLAA in Section 4.3.1. Further evaluation is documented in Section 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 treated water/steam addressed as a TLAA in Section 4.3.1. Further evaluation is documented in Section 3.1.2.2.1.
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 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 Section 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 PSL 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 stainless steel and steel (with stainless steel cladding), piping components and bolting is addressed as a TLAA in Section 4.3.1. Cumulative fatigue damage in the pressurizer surge line is addressed with a plant specific AMP. Further evaluation is documented in Section 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 / 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 stainless steel, steel (with or without stainless steel or nickel alloy cladding) and nickel alloy steam generator components exposed to reactor coolant is addressed as a TLAA in Section 4.3.1. Further evaluation is documented in Section 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 stainless steel and nickel alloy cladding) pressurizer components exposed to reactor coolant is addressed as a TLAA in Section 4.3.1. Further evaluation is documented in Section 3.1.2.2.1.
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 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 Section 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 / TLAA	Further Evaluation Recommended	Discussion
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 Section 3.1.2.2.1.
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)	Consistent with NUREG-2191. Loss of material due to general, pitting, and crevice corrosion is managed using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry AMPs for steel steam generator components. Further evaluation is documented in Section 3.1.2.2.2.1 and 3.1.2.2.2.2.
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. Loss of fracture toughness due to neutron irradiation embrittlement is addressed as a TLAA in Section 4.2 which is credited for managing loss of fracture toughness in steel reactor vessel lower and intermediate shells exposed to reactor coolant and neutron flux. Further evaluation is documented in Section 3.1.2.2.3.1.
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 with exception for the Reactor Vessel Material Surveillance AMP. Loss of fracture toughness due to neutron irradiation embrittlement of the steel reactor vessel lower and intermediate shells will be managed with the Reactor Vessel Material Surveillance and Neutron Fluence Monitoring AMPs. Further evaluation is documented in Section 3.1.2.2.3.2.

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 / TLAA	Further Evaluation Recommended	Discussion
3.1-1, 015	This line item only applies to B&W designs. PSL utilizes Combustion Engineering 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 PSL reactor vessel shells. Further evaluation is documented in Section 3.1.2.2.5.
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 AMP	Yes (SRP-SLR Section 3.1.2.2.6.1)	Not applicable. PSL does not use a bottom-mounted design for guide tubes. Further evaluation is documented in Section 3.1.2.2.6.1
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)	Consistent with NUREG-2191. The Water Chemistry AMP is used to manage cracking due to SCC in Class 1 CASS piping and piping components exposed to reactor coolant. A plant-specific AMP is not necessary for further management. Further evaluation is documented in Section 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 AMP	Yes (SRP-SLR Section 3.1.2.2.8)	Not applicable. This component does not exist at PSL. Further evaluation is documented in Section 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 / 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)	Consistent with NUREG-2191. The Steam Generators and Water Chemistry AMPs are used to manage cracking due to primary water SCC in the Unit 2 divider plates. Further evaluation is documented in Section 3.1.2.2.11.
3.1-1, 028	Westinghouse-specific "Existing Programs" components: Stainless steel, nickel alloy , and X-750 control rod guide tube support pins (split pins) exposed to reactor coolant and neutron flux	Loss of material due to wear; cracking due to SCC, IASCC, 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. PSL is a Combustion Engineering design.
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	Not applicable. This line item only applies to Babcock and Wilcox designs.				
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 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry AMPs are used to manage cracking due to 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 PSL pressurizer relief tanks are not an in scope component.

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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 AMP is used to manage cracking due to cyclic loading in stainless steel and steel with stainless steel cladding RCS piping and fittings exposed to reactor coolant.
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 AMP is used to manage cracking due to cyclic loading in the steel 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 AMP is used to manage loss of material due to wear of the steel 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 AMP is used to manage loss of fracture toughness due to thermal aging embrittlement 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 / 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, Water Chemistry and ASME Code Class 1 Small-Bore Piping 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 AMP is used to manage cracking due to cyclic loading in stainless steel, steel with stainless steel cladding, and steel with nickel alloy cladding pressurizer components exposed to reactor coolant.
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 and Water Chemistry AMPs are used to manage cracking due to primary water SCC in the nickel alloy core stabilizing lugs, core stop lugs, and flow baffles exposed to reactor coolant.
3.1-1, 041	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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 and Water Chemistry AMPs are used to manage cracking due to SCC and primary water SCC in stainless steel, steel with stainless steel cladding, or steel with nickel alloy cladding, and steel with stainless steel insert pressurizer components exposed to reactor coolant.
3.1-1, 043	Not applicable. This line item only applies to BWRs.				
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 AMP is used to manage loss of material due to erosion of the Unit 1 steel steam generator secondary manway and handhole closure cover seating surfaces exposed to treated water and 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, Water Chemistry, and Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in RCPB Components AMPs are used to manage cracking due to primary water SCC in nickel alloy and steel with nickel alloy diaphragm reactor coolant pressure boundary components exposed to reactor coolant. Additionally, primary water SCC in the Unit 2 structural weld overlays is addressed as a TLAA in Section 4.7.8.

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 / 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 and Water Chemistry AMPs are used to manage cracking due to SCC and primary water SCC in stainless steel and steel with stainless steel cladding reactor vessel 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 and Water Chemistry AMPs are used to manage cracking due to SCC and primary water SCC in stainless steel reactor vessel head penetration pressure housings exposed to reactor coolant.
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 and Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in RCPB Components AMPs are used to manage loss of material due to boric acid corrosion in reactor vessel closure head steel external surfaces adjacent to dissimilar metal (Alloy 82/182) welds 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 / TLAA	Further Evaluation Recommended	Discussion
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 and closure bolting exposed to air with borated water leakage.
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 Bolting Integrity AMP is used to manage loss of preload due to thermal effects, gasket creep, and self-loosening in the steel pressurizer manway cover bolts and steel closure bolting for RCS piping components exposed to air-indoor uncontrolled.
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	Stainless steel, nickel alloy Combustion Engineering reactor internal "Primary" components exposed to reactor coolant, neutron flux	Cracking due to SCC, IASCC, 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, as modified by SLR-ISG-2021-01-PWRVI. The Reactor Vessel Internals and Water Chemistry AMPs are used to manage cracking due to SCC, IASCC, and fatigue in stainless steel reactor internal “Primary” components exposed to reactor coolant and neutron flux. Further evaluation is documented in Section 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 / TLAA	Further Evaluation Recommended	Discussion
3.1-1, 052b	Stainless steel, nickel alloy Combustion Engineering reactor internal "Expansion" components exposed to reactor coolant, neutron flux	Cracking due to SCC, IASCC, 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, as modified by SLR-ISG-2021-01-PWRVI. The Reactor Vessel Internals and Water Chemistry AMPs are used to manage cracking due to SCC, IASCC, and fatigue in stainless steel reactor internal “Expansion” components exposed to reactor coolant and neutron flux. Further evaluation is documented in Section 3.1.2.2.9.
3.1-1, 052c	Stainless steel, nickel alloy Combustion Engineering reactor internal "Existing Programs" components exposed to reactor coolant, neutron flux	Cracking due to SCC, IASCC, 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, as modified by SLR-ISG-2021-01-PWRVI. The Reactor Vessel Internals and Water Chemistry AMPs are used to manage cracking due to SCC, IASCC, and fatigue in stainless steel reactor internal “Existing Programs” components exposed to reactor coolant and neutron flux. Further evaluation is documented in Section 3.1.2.2.9.
3.1-1, 053a	Not applicable. This line item only applies to Westinghouse designs.				
3.1-1, 053b	Not applicable. This line item only applies to Westinghouse designs.				
3.1-1, 053c	Not applicable. This line item only applies to Westinghouse designs.				
3.1-1, 054	Not applicable. This line item only applies to Westinghouse designs.				
3.1-1, 055a	Not applicable. This line item only applies to Babcock and Wilcox designs.				
3.1-1, 055b	Stainless steel, nickel alloy Combustion Engineering 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, as modified by SLR-ISG-2021-01-PWRVI. The Reactor Vessel Internals AMP is used to manage stainless steel reactor internal “No Additional Measures” components exposed to reactor coolant and neutron flux. Further evaluation is documented in Section 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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 055c	Not applicable. This line item only applies to Westinghouse designs.				
3.1-1, 056a	Stainless steel (SS, including CASS, PH SS, or martensitic SS) or nickel alloy Combustion Engineering 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, as modified by SLR-ISG-2021-01-PWRVI. The Reactor Vessel Internals AMP is used to manage changes in dimension and loss of fracture toughness in stainless steel reactor internal “Primary” components exposed to reactor coolant and flux. Further evaluation is documented in Section 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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 056b	Stainless steel (SS, including CASS, PH SS, or martensitic SS) Combustion Engineering "Expansion" reactor internal 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, as modified by SLR-ISG-2021-01-PWRVI. The Reactor Vessel Internals AMP is used to manage loss of fracture toughness in stainless steel reactor internal “Expansion” components exposed to reactor coolant and flux. Further evaluation is documented in Section 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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 056c	Stainless steel (SS, including CASS, PH SS, or martensitic SS) or nickel alloy Combustion Engineering 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)	Consistent with NUREG-2191, as modified by SLR-ISG-2021-01-PWRVI. The Reactor Vessel Internals AMP is used to manage loss of fracture toughness, loss of preload, and loss of material in stainless steel reactor internal "Existing" components exposed to reactor coolant and flux. Further evaluation is documented in Section 3.1.2.2.9.
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.				
3.1-1, 059a	Not applicable. This line item only applies to Westinghouse designs.				
3.1-1, 059b	Not applicable. This line item only applies to Westinghouse designs.				
3.1-1, 059c	Not applicable. This line item only applies to Westinghouse designs.				
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 AMP is used to manage wall thinning due to flow-accelerated corrosion in the steel steam generator feedwater nozzles, blowdown, nozzles, steam outlet nozzles, and the Unit 2 secondary instrument nozzles exposed to treated water/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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 AMP is used to manage cracking due to SCC in stainless steel RCPB bolting exposed to air-indoor uncontrolled.
3.1-1, 063	Not applicable. This line item only applies to BWRs.				
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 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. PSL does not have control rod drive head penetration flange bolting.
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 AMP is used to manage loss of preload due to thermal effects, gasket creep, and self-loosening in the steel pressurizer manway cover bolts and steel closure bolting for RCS piping components exposed to air-indoor uncontrolled.
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 AMP is used to manage loss of preload due to thermal effects, gasket creep, and self-loosening in steel 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 PSL steam generator tube support plates are not carbon steel.

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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 and Water Chemistry AMPs are used to manage cracking due to outer diameter SCC and intergranular attack in nickel alloy U-tubes exposed to treated feedwater and steam.
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 and Water Chemistry AMPs are used to manage cracking due to primary water SCC in nickel alloy U-tubes, tube plugs, and Unit 2 tube stabilizers (stakes) exposed to reactor coolant.
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 and Water Chemistry AMPs are used to manage cracking due to SCC, loss of material due to general (steel only), pitting, and crevice corrosion in stainless steel, and nickel alloy steam generator components exposed to treated water 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 and Water Chemistry AMPs are used to manage loss of material due to general, pitting, and crevice corrosion, erosion, and ligament cracking due to corrosion in the steel steam generator tube bundle wrapper and supports, Unit 1 moisture separators, tubesheets, and Unit 1 feedwater feedring exposed to treated water 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 PSL Steam Generators.

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 / 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 and Water Chemistry AMPs are used to manage wall thinning due to flow-accelerated corrosion in the Unit 1 steel feedwater ring and moisture separators exposed to treated water 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. Steel tube support lattice bars are not a PSL 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 AMP is used to manage loss of material due to wear and fretting of the stainless steel Unit 1 tube support lattice bars and the stainless steel Unit 2 tube support plates and anti-vibration bars exposed to treated water 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 AMP is used to manage loss of material due to wear and fretting of the nickel alloy U-tubes exposed to treated water or steam.
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.				

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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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	Not applicable. The pressurizer relief tank and respective components are not within the scope of subsequent license renewal for PSL.
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 RAI 2.3.1-1 (Reference ML022810608), the pressurizer spray head is not within the scope of subsequent license renewal at PSL.
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 RAI 2.3.1-1 (Reference ML022810608), the pressurizer spray head is not within the scope of subsequent license renewal at PSL.
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 used. Loss of material due to general, pitting and crevice corrosion of steel steam generator shell assembly exposed to treated water or steam is addressed in Item Number 3.1-1, 012.
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	Consistent with NUREG-2191. The Water Chemistry AMP is used to manage cracking due to SCC of the Unit 1 stainless steel divider plate and Unit 2 tube stabilizers (stakes) exposed to reactor coolant.
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	Consistent with NUREG-2191, as modified by SLR-ISG-2021-01-PWRVI. The Water Chemistry AMP is used to manage loss of material due to pitting and crevice corrosion of stainless steel reactor internal components 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 / 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 AMP is used to manage loss of material due to pitting and crevice corrosion in stainless steel, nickel alloy, CASS, steel with nickel alloy cladding, 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 PSL 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 PSL.
3.1-1, 091	Not applicable. This line item only applies to BWRs.				
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 with exception. The Reactor Head Closure Stud Bolting 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 high-strength steel reactor head closure studs, nuts, and washers 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 PSL 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.				

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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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.				
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 PSL reactor coolant system piping or piping components exposed to concrete. Further evaluation is documented in Section 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	Not used. Boric acid corrosion is not an applicable aging effect in stainless steel; the associated NUREG-2191 aging items are not used.
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 and Steam Generators AMPs are used to manage reduction of heat transfer due to fouling in the nickel alloy steam generator U-tubes exposed to treated water or steam.
3.1-1, 113	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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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, reactor vessel interior 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, PWSCC, IASCC (SCC mechanisms for stainless steel, nickel alloy components only), fatigue, or cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, or 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	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 IGSCC, PWSCC, IASCC (SCC mechanisms for stainless steel, nickel alloy components only), fatigue, or cyclic loading; loss of material due to general corrosion, or wear in reactor vessel internal components exposed to reactor coolant and neutron flux.
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 PSL stainless steel reactor coolant system piping or piping components exposed to concrete. Further evaluation is documented in Section 3.1.2.2.15.
3.1-1, 116	Not applicable. This line item only applies to Westinghouse designs.				
3.1-1, 117	Not applicable. This line item only applies to Westinghouse 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 / TLAA	Further Evaluation Recommended	Discussion
3.1-1, 118	Reactor vessel internal components or LRA/SLRA-specified reactor vessel internal component	Cracking due to SCC, IASCC, cyclic loading, fatigue	Plant-specific AMP or AMP XI.M16A, "PWR Vessel Internals," and AMP XI.M2, "Water Chemistry" (SCC and IASCC only), with an adjusted site-specific or component-specific aging management basis for a specified reactor vessel internal component	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191, as modified by SLR-ISG-2021-01-PWRVI. The Water Chemistry and Reactor Vessel Internals AMPs are used to manage cracking due to SCC, IASCC, cyclic loading and fatigue in the stainless steel reactor vessel internal components exposed to reactor coolant, neutron flux. Further evaluation is documented in Section 3.1.2.2.9.
3.1-1, 119	Stainless steel, nickel alloy, stellite PWR reactor vessel internal components or LRA/SLRA-specified reactor vessel internal component 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 AMP or AMP XI.M16A, "PWR Vessel Internals," with an adjusted site-specific or component-specific aging management basis for a specified reactor vessel internal component	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191, as modified by SLR-ISG-2021-01-PWRVI. The Reactor Vessel Internals AMP is used to manage loss of material and changes in dimension for stainless steel reactor vessel internal core shroud tie rods and fuel alignment plate. Loss of preload of the stainless steel core support barrel expandable plugs and patches is managed by TLAA Section 4.7.3. Other noted aging effects/mechanisms are addressed with more appropriate line items. Note that many aging effects managed by the Reactor Vessel Internals AMP are dispositioned through FMECA analysis and not inspected. Further evaluation is documented in Section 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.				

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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 AMP is used to manage loss of material due to general, pitting, and crevice corrosion in steel, steel with nickel alloy cladding, and steel with stainless steel cladding piping and piping components exposed to air-indoor uncontrolled.
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 AMP is used to manage cracking due to flow-induced vibration and high-cycle fatigue in nickel alloy U-tubes exposed to treated water 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 and Steam Generator AMPs are used to manage loss of material due to boric acid corrosion in steel with stainless steel and nickel alloy cladding steam generator channel head nozzles, stay cylinders, primary heads, and tubesheets 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. 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 / 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 AMP is used to manage loss of material due to pitting and crevice corrosion in stainless steel, CASS, and nickel alloy piping and piping components exposed to air. Further evaluation is documented in Section 3.1.2.2.16.
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 PSL reactor coolant system.
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)	Not used. The PSL 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 Section 3.1.2.2.6.3.

Table 3.1.2-1: Reactor Vessels – Summary 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	Carbon steel with stainless steel cladding	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	Carbon steel with stainless steel cladding	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
Bottom head	Pressure boundary	Carbon steel with stainless steel cladding	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.A2.RP-234	3.1-1, 046	C
Bottom head	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A
CEDM motor housing lower end fitting	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	A
CEDM motor housing lower end fitting	Pressure boundary	Nickel alloy	Reactor coolant (int)	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
CEDM motor housing lower end fitting	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A

Table 3.1.2-1: Reactor Vessels – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
CEDM motor housing upper pressure 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
CEDM motor housing upper pressure 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	A
CEDM motor housing upper pressure housing	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.A2.RP-55	3.1-1, 047	A
CEDM motor housing upper pressure housing	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A
CEDM nozzle tubes and 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	A
CEDM nozzle tubes and adapter	Pressure boundary	Nickel alloy	Reactor coolant (int)	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
CEDM nozzle tubes and adapter	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A

Table 3.1.2-1: Reactor Vessels – Summary 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 head (mono-block forging)	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)	IV.C2.R-431	3.1-1, 124	C
Closure head (mono-block forging)	Pressure boundary	Carbon steel with stainless steel cladding	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 (mono-block forging)	Pressure boundary	Carbon steel with stainless steel cladding	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.A2.RP-234	3.1-1, 046	C
Closure head (mono-block forging)	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A
Closure studs, nuts, and 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, and 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, and 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 stabilizing lugs	Structural support	Nickel alloy	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.A2.RP-57	3.1-1, 040a	A

Table 3.1.2-1: Reactor Vessels – Summary 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 stabilizing lugs	Structural support	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	C
Core stop lugs	Structural support	Nickel alloy	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.A2.RP-57	3.1-1, 040a	A
Core stop lugs	Structural support	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	C
Flow baffles	Flow distribution	Nickel alloy	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.A2.RP-57	3.1-1, 040a	C
Flow baffles	Flow distribution	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	C
ICI nozzle adapters	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
ICI nozzle adapters	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
ICI nozzle adapters	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.A2.RP-55	3.1-1, 047	A
ICI nozzle adapters	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A

Table 3.1.2-1: Reactor Vessels – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
ICI nozzle tubes	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	A
ICI nozzle tubes	Pressure boundary	Nickel alloy	Reactor coolant (int)	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
ICI nozzle tubes	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A
ICI seal carrier assemblies	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
ICI seal carrier assemblies	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
ICI seal carrier assemblies	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.A2.RP-55	3.1-1, 047	A
ICI seal carrier assemblies	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A

Table 3.1.2-1: Reactor Vessels – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Insulation support ring (Unit 1)	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
Insulation support ring (Unit 1)	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
Nozzle 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
Nozzle support pads	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/outlet nozzle safe ends	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)	IV.C2.R-431	3.1-1, 124	A
Primary inlet/outlet nozzle safe ends	Pressure boundary	Carbon steel with stainless steel cladding	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/outlet nozzle safe ends	Pressure boundary	Carbon steel with stainless steel cladding	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.A2.RP-234	3.1-1, 046	A
Primary inlet/outlet nozzle safe ends	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A
Primary inlet/outlet nozzles	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)	IV.C2.R-431	3.1-1, 124	A

Table 3.1.2-1: Reactor Vessels – Summary 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/outlet nozzles	Pressure boundary	Carbon steel with stainless steel cladding	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/outlet nozzles	Pressure boundary	Carbon steel with stainless steel cladding	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.A2.RP-234	3.1-1, 046	A
Primary inlet/outlet nozzles	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A
Reactor vessel components with fatigue analysis	Pressure boundary	Carbon steel Nickel alloy Stainless steel	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 rings	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 rings	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
RVLMS pressure housing (Unit 1)	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
RVLMS pressure housing (Unit 1)	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
RVLMS pressure housing (Unit 1)	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.A2.RP-55	3.1-1, 047	A

Table 3.1.2-1: Reactor Vessels – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
RVLMS pressure housing (Unit 1)	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A
RVLMS pressure housing lower end fitting (Unit 1)	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	A
RVLMS pressure housing lower end fitting (Unit 1)	Pressure boundary	Nickel alloy	Reactor coolant (int)	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
RVLMS pressure housing lower end fitting (Unit 1)	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A
RVLMS upper flange (Unit 1)	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
RVLMS upper flange (Unit 1)	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
RVLMS upper flange (Unit 1)	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.A2.RP-55	3.1-1, 047	A

Table 3.1.2-1: Reactor Vessels – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
RVLMS upper flange (Unit 1)	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A
Service structure support pad (Unit 2)	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
Service structure support pad (Unit 2)	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
Shells (lower, intermediate)	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int) 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 (lower, intermediate)	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int) Neutron flux (int)	Loss of fracture toughness	TLAA – Section 4.2, Reactor Vessel Neutron Embrittlement	IV.A2.R-84	3.1-1, 013	A
Shells (lower, intermediate, upper)	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)	IV.C2.R-431	3.1-1, 124	C
Shells (lower, intermediate, upper)	Pressure boundary	Carbon steel with stainless steel cladding	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 (lower, intermediate, upper)	Pressure boundary	Carbon steel with stainless steel cladding	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.A2.RP-234	3.1-1, 046	C
Shells (lower, intermediate, upper)	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A

Table 3.1.2-1: Reactor Vessels – Summary 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	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
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	A
Vent pipe	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.A2.RP-234	3.1-1, 046	A
Vent pipe	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A
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	A
Vent pipe nozzle	Pressure boundary	Nickel alloy	Reactor coolant (int)	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
Vent pipe nozzle	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A

Table 3.1.2-1: Reactor Vessels – Summary 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 closure flange and studs	Mechanical closure	High-strength steel	Air – indoor uncontrolled (ext)	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.A2.RP-254	3.1-1, 001	A
Vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel cladding	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 cladding	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 cladding	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.A2.RP-234	3.1-1, 046	C
Vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel cladding	Reactor coolant (int)	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
Vessel flange	Pressure boundary Structural support	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.A2.RP-28	3.1-1, 088	A
Vessel flange	Structural support	Carbon steel with stainless steel cladding	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

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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.

Plant Specific Notes

None.

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
"No Additional Measures" components	Structural support Flow distribution	Stainless steel Nickel alloy	Reactor coolant Neutron flux	No additional aging management	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-306	3.1-1, 055b	A
ASME Section XI, examination category B-N-3 reactor vessel internals components	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) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A
Core barrel assembly: upper flange	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-332	3.1-1, 056c	A
Core shroud assembly: remaining 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.B3.RP-323	3.1-1, 052b	A
Core shroud assembly: remaining axial welds	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-359a	3.1-1, 056b	A
Core shroud plate-former plate weld	Structural support	Stainless steel	Reactor coolant Neutron flux	Changes in dimension Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-359	3.1-1, 056a	A
Core shroud plate-former plate weld	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B3.RP-322	3.1-1, 052a	A
Core shroud tie rods	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B3.R-423	3.1-1, 118	A, 1
Core shroud tie rods	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material Changes in dimension	Reactor Vessel Internals (B.2.3.7)	IV.B3.R-424	3.1-1, 119	A, 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 stabilizing lugs, shims, and bolts	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-320a	3.1-1, 052c	A, 1
Core support barrel assembly: lower 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.B3.RP-362c	3.1-1, 052b	A
Core support barrel assembly: lower axial weld	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-362b	3.1-1, 056b	A
Core support 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.B3.RP-333	3.1-1, 052b	A
Core support 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.B3.RP-333a	3.1-1, 056b	A
Core support barrel assembly: middle 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.B3.RP-362c	3.1-1, 052b	A
Core support barrel assembly: middle axial weld	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-362b	3.1-1, 056b	A
Core support barrel assembly: middle 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.B3.RP-362a	3.1-1, 052a	A
Core support barrel assembly: middle girth weld	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-362	3.1-1, 056a	A
Core support 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.B3.RP-327	3.1-1, 052a	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
Core support barrel assembly: upper girth weld and 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.B3.RP-329	3.1-1, 052b	A
Core support barrel assembly: upper girth weld and upper axial weld	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B3.R-455	3.1-1, 056b	A
Core support barrel expandable plugs and patches (Unit 1)	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B3.RP-423	3.1-1, 118	A
Core support barrel expandable plugs and patches (Unit 1)	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of preload	TLAA – Section 4.7.3, Unit 1 Core Support Barrel Repair Plug Preload Relaxation	IV.B3.RP-424	3.1-1, 119	A
Core support barrel flexure weld	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B3.RP-328	3.1-1, 052a	A
Core support columns	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B3.RP-363	3.1-1, 052b	A
Core support columns	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-364	3.1-1, 056b	A
Core support plate	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-343	3.1-1, 052a	A
Core support plate	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-365	3.1-1, 056a	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
Fuel alignment plate	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B3.R-423	3.1-1, 118	A, 2
Fuel alignment plate	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material Changes in dimension	Reactor Vessel Internals (B.2.3.7)	IV.B3.R-424	3.1-1, 119	A, 2
Guide lugs, guide lug inserts, and bolts	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-320	3.1-1, 052C	A
Guide lugs, guide lug inserts, and bolts	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material Loss of preload	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-319	3.1-1, 056c	A
Lower core support beams	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B3.RP-335	3.1-1, 052b	A
Lower support structure: 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.B3.RP-334	3.1-1, 052c	A
Lower support structure: fuel alignment pins	Structural support	Stainless steel	Reactor coolant Neutron flux	Loss of material Loss of fracture toughness Loss of preload	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-336	3.1-1, 056c	A
Peripheral instrument guide tubes	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B3.RP-312	3.1-1, 052a	A
Reactor vessel internal components	Structural support Flow distribution	Stainless steel Nickel alloy	Reactor coolant Neutron flux	Loss of material	Water Chemistry (B.2.3.2)	IV.B3.RP-24	3.1-1, 087	A
Reactor vessel internal components with a fatigue analysis	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Cumulative fatigue damage	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.B3.RP-339	3.1-1, 003	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**
Remaining instrument guide tubes	Structural support	Stainless steel	Reactor coolant Neutron flux	Cracking	Reactor Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B3.RP-313	3.1-1, 052b	A
Welded core shroud assembly	Structural support Flow distribution	Stainless steel	Reactor coolant Neutron flux	Changes in dimension Loss of fracture toughness	Reactor Vessel Internals (B.2.3.7)	IV.B3.RP-326	3.1-1, 056a	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

1. Per Appendix C these components are added to the Primary inspection category in the Reactor Vessel Internals AMP.
2. Per Appendix C the fuel alignment plate is added to the Expansion category in the Reactor Vessel Internals AMP.

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**
Alloy 600 small bore nozzle repairs (Unit 2)	Pressure boundary	Carbon steel	Reactor coolant (int)	Loss of material	TLAA – Section 4.7.2, Alloy 600 Instrument Nozzle Repairs	N/A	N/A	G, 1
Heater sheath and 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	C
Heater sheath and thermowell	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
Heater sheath and 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.R-217	3.1-1, 033	A
Heater sheath and 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	A
Heater sleeves	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 3.1.2-3: 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 sleeves	Pressure boundary	Nickel alloy	Reactor coolant (int)	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.C2.RP-37	3.1-1, 045	A
Heater sleeves	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Instrument 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	A
Instrument nozzle	Pressure boundary	Nickel alloy	Reactor coolant (int)	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.C2.RP-156	3.1-1, 045	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**
Instrument nozzle	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Lower head (Unit 1)	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)	IV.C2.R-431	3.1-1, 124	C
Lower head (Unit 1)	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-58	3.1-1, 040	A
Lower head (Unit 1)	Pressure boundary	Carbon steel with stainless steel cladding	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-25	3.1-1, 042	A
Lower head (Unit 1)	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Lower head (Unit 2)	Pressure boundary	Carbon steel with nickel alloy cladding	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
Lower head (Unit 2)	Pressure boundary	Carbon steel with nickel alloy cladding	Reactor coolant (int)	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**
Lower head (Unit 2)	Pressure boundary	Carbon steel with nickel alloy cladding	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-25	3.1-1, 042	A
Lower head (Unit 2)	Pressure boundary	Carbon steel with nickel alloy cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
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
Manway cover	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant (int)	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 (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-25	3.1-1, 042	A
Manway cover	Pressure boundary	Carbon steel with stainless steel insert	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	C
Manway cover 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
Manway cover 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

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 subject to fatigue	Pressure boundary	Carbon steel with stainless steel clad Carbon steel with nickel alloy clad Stainless steel Nickel alloy	Reactor coolant (int)	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.C2.R-223	3.1-1, 009	A
Safety valve flanges	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
Safety valve flanges	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
Safety valve flanges	Pressure boundary	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-58	3.1-1, 040	A
Safety valve flanges	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-25	3.1-1, 042	A
Safety valve flanges	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Shell	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)	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
Shell	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-58	3.1-1, 040	A
Shell	Pressure boundary	Carbon steel with stainless steel cladding	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-25	3.1-1, 042	A
Shell	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Spray nozzle, surge nozzle, relief valve nozzle, safety valve nozzle	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)	IV.C2.R-431	3.1-1, 124	A
Spray nozzle, surge nozzle, relief valve nozzle, safety valve nozzle	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-58	3.1-1, 040	A
Spray nozzle, surge nozzle, relief valve nozzle, safety valve nozzle	Pressure boundary	Carbon steel with stainless steel cladding	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-25	3.1-1, 042	A
Spray nozzle, surge nozzle, relief valve nozzle, safety valve nozzle	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	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	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
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
Surge nozzle and relief valve nozzle structural weld overlay (Unit 2)	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	A
Surge nozzle and relief valve nozzle structural weld overlay (Unit 2)	Pressure boundary	Nickel alloy	Reactor coolant (int)	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.C2.RP-156	3.1-1, 045	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
Surge nozzle and relief valve nozzle structural weld overlay (Unit 2)	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Surge nozzle safe end (Unit 2)	Pressure boundary	CASS	Reactor coolant (int)	Cracking	Water Chemistry (B.2.3.2)	IV.C2.R-05	3.1-1, 020	E, 2
Surge nozzle safe end (Unit 2)	Pressure boundary	CASS	Reactor coolant (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
Surge nozzle safe ends, spray nozzle safe ends, relief valve 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	A
Surge nozzle safe ends, spray nozzle safe ends, relief valve 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
Surge nozzle safe ends, spray nozzle safe ends, relief valve nozzle safe ends	Pressure boundary	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-58	3.1-1, 040	A
Surge nozzle safe ends, spray nozzle safe ends, relief valve nozzle safe ends	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-25	3.1-1, 042	A
Surge nozzle safe ends, spray nozzle safe ends, relief valve nozzle safe ends	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	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
Thermal sleeve (spray nozzle, surge nozzle) (Unit 1)	Insulate (thermal)	Stainless steel	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-58	3.1-1, 040	A
Thermal sleeve (spray nozzle, surge nozzle) (Unit 1)	Insulate (thermal)	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-25	3.1-1, 042	A
Thermal sleeve (spray nozzle, surge nozzle) (Unit 1)	Insulate (thermal)	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Upper head	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)	IV.C2.R-431	3.1-1, 124	C
Upper head	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C2.R-58	3.1-1, 040	A
Upper head	Pressure boundary	Carbon steel with stainless steel cladding	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-25	3.1-1, 042	A
Upper head	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP 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 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.
G. Environment not in NUREG-2191 for this component and material.

Plant Specific Notes

1. A plant specific TLAA, Section 4.7.2, “Alloy 600 Instrument Nozzle Repairs,” is used to manage the pressurizer Alloy 600 instrument nozzle and pressurizer heater nozzle repairs.
2. Per Section 3.1.2.2.6.2, cracking due to SCC in Class 1 RCS components is managed by the Water Chemistry AMP.

Table 3.1.2-4: Reactor Coolant 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**
Alloy 600 small bore nozzle repairs	Pressure boundary	Carbon steel	Reactor coolant (int)	Loss of material	TLAA – Section 4.7.2, Alloy 600 Instrument Nozzle Repairs	N/A	N/A	G, 1
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	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-44	3.1-1, 011	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

Table 3.1.2-4: Reactor Coolant 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
Dissimilar metal welds	Pressure boundary	Nickel alloy	Reactor coolant (int)	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.C2.RP-159	3.1-1, 045	A
Dissimilar metal welds	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Flexible hoses	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
Flexible hoses	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
Flexible hoses	Pressure boundary	Stainless steel	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 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
Flexible hoses	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
Flexible hoses	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	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)	IV.C2.R-452b	3.1-1, 136	A
Flow element	Pressure boundary	Stainless steel	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
Flow element	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
Flow element	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Flow element	Throttle	Stainless steel	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 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 element	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
Flow element	Throttle	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Nozzle	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)	IV.C2.R-431	3.1-1, 124	A
Nozzle	Pressure boundary	Carbon steel with stainless steel cladding	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
Nozzle	Pressure boundary	Carbon steel with stainless steel cladding	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
Nozzle	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
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	A

Table 3.1.2-4: Reactor Coolant 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**
Nozzle	Pressure boundary	Nickel alloy	Reactor coolant (int)	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.C2.RP-159	3.1-1, 045	A
Nozzle	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	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)	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)	IV.C2.R-56	3.1-1, 035	A

Table 3.1.2-4: Reactor Coolant 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)	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
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	A
Orifice	Throttle	Stainless steel	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
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
Orifice	Throttle	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Piping	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)	IV.C2.R-431	3.1-1, 124	A
Piping	Pressure boundary	Carbon steel with stainless steel cladding	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 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	Pressure boundary	Carbon steel with stainless steel cladding	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
Piping	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Piping	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	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	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	Pressure boundary	CASS	Reactor coolant (int)	Cracking	Water Chemistry (B.2.3.2)	IV.C2.R-05	3.1-1, 020	A
Piping	Pressure boundary	CASS	Reactor coolant (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	Pressure boundary	CASS	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A

Table 3.1.2-4: Reactor Coolant 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	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)	IV.C2.R-452b	3.1-1, 136	A
Piping	Pressure boundary	Stainless steel	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	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	C
Piping	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Piping (pressurizer surge line)	Pressure boundary	CASS	Reactor coolant (int)	Cumulative fatigue damage Cracking	Pressurizer Surge Line (B.2.3.44)	IV.C2.R-18	3.1-1, 005	E, 2
Piping < 4 inches	Pressure boundary	CASS	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

Table 3.1.2-4: Reactor Coolant 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 < 4 inches	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
Piping and piping components	Pressure boundary	Carbon steel Stainless steel	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	Pressure boundary	Carbon steel Stainless steel	Reactor coolant (int)	Cumulative fatigue damage Cracking	TLAA – Section 4.3.2, Metal Fatigue of Non-Class 1 Components	IV.C2.R-18	3.1-1, 005	A
Piping and piping components	Structural integrity (attached)	Carbon steel Stainless steel	Reactor coolant (int)	Cumulative fatigue damage Cracking	TLAA – Section 4.3.2, Metal Fatigue of Non-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

Table 3.1.2-4: Reactor Coolant 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)	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	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
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	A
Pump casing and cover	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 and cover	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 and cover	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	C
Pump casing and cover	Pressure boundary	CASS	Reactor coolant (int)	Cracking	Water Chemistry (B.2.3.2)	IV.C2.R-05	3.1-1, 020	A
Pump casing and cover	Pressure boundary	CASS	Reactor coolant (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

Table 3.1.2-4: Reactor Coolant 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 and cover	Pressure boundary	CASS	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
RCP lower seal heat exchanger tubes	Pressure boundary	Stainless steel	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
RCP lower seal heat exchanger tubes	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
RCP lower seal heat exchanger tubes	Pressure boundary	Stainless steel	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
RCP lower seal heat exchanger 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	C
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
Structural weld overlay repairs	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 3.1.2-4: Reactor Coolant 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
Structural weld overlay repairs	Pressure boundary	Nickel alloy	Reactor coolant (int)	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.C2.RP-159	3.1-1, 045	C
Structural weld overlay repairs	Pressure boundary	Nickel alloy	Reactor coolant (int)	Cumulative fatigue damage Cracking	TLAA – Section 4.3.1, Metal Fatigue of Class 1 Components	IV.C2.R-223	3.1-1, 009	A
Structural weld overlay repairs	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	C
Structural weld overlay repairs (Unit 2)	Pressure boundary	Nickel alloy	Reactor coolant (int)	Cracking	TLAA – Section 4.7.8, Unit 2 Structural Weld Overlay PWSCC Crack Growth Analyses	IV.C2.RP-159	3.1-1, 045	E, 3
Thermowell	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	A

Table 3.1.2-4: Reactor Coolant 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	Nickel alloy	Reactor coolant (int)	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.C2.RP-159	3.1-1, 045	A
Thermowell	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	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
Thermowell	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
Thermowell	Pressure boundary	Stainless steel	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 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
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	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
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	A
Valve body	Pressure boundary	CASS	Reactor coolant (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	CASS	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	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

Table 3.1.2-4: Reactor Coolant 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	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	Stainless steel	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	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
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	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP 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 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.
G. Environment not in NUREG-2191 for this component and material.

Plant Specific Notes

1. A plant specific TLAA, Section 4.7.2, “Alloy 600 Instrument Nozzle Repairs,” is used to manage the Alloy 600 reactor coolant nozzle repairs.
2. A plant specific AMP, Pressurizer Surge Line (B.2.3.44), is used to manage fatigue in the pressurizer surge line.

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 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	A
Blowdown nozzles	Pressure boundary	Carbon steel	Treated water (int)	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
Blowdown nozzles	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	IV.D1.R-37	3.1-1, 061	C
Bolting	Mechanical closure	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	IV.D1.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.D1.RP-46	3.1-1, 067	A
Conical skirt	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
Divider plates (Unit 1)	Flow distribution	Stainless steel	Reactor coolant (ext)	Cracking	Water Chemistry (B.2.3.2)	IV.D1.RP-17	3.1-1, 086	A
Divider plates (Unit 2)	Flow distribution	Nickel alloy	Reactor coolant (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-367	3.1-1, 025	A, 1
Divider plates (Unit 2)	Flow distribution	Nickel alloy	Reactor coolant (ext)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	C
Feedwater feedring (Unit 1)	Structural integrity (attached) Direct flow	Carbon steel	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-161	3.1-1, 072	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
Feedwater feedring (Unit 1)	Structural integrity (attached) Direct flow	Carbon steel	Treated water (int)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-161	3.1-1, 072	C
Feedwater feedring (Unit 1)	Structural integrity (attached) Direct flow	Carbon steel	Treated water (int)	Wall thinning – FAC	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-49	3.1-1, 074	A
Feedwater feedring (Unit 2)	Structural integrity (attached) Direct flow	Stainless steel	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	C
Feedwater feedring (Unit 2)	Structural integrity (attached) Direct flow	Stainless steel	Treated water (int)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	C
Feedwater feedring (Unit 2)	Structural integrity (attached) Direct flow	Stainless steel	Treated water >140°F (ext) Steam (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	C
Feedwater feedring (Unit 2)	Structural integrity (attached) Direct flow	Stainless steel	Treated water >140°F (int)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	C
Feedwater j- nozzle (Unit 1)	Structural integrity (attached) Direct flow	Nickel alloy	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	C
Feedwater j- nozzle (Unit 1)	Structural integrity (attached) Direct flow	Nickel alloy	Treated water (int)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	C
Feedwater j- nozzle (Unit 1)	Structural integrity (attached) Direct flow	Nickel alloy	Treated water >140°F (ext) Steam (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	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
Feedwater j- nozzle (Unit 1)	Structural integrity (attached) Direct flow	Nickel alloy	Treated water >140°F (int)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	C
Feedwater j-nozzle (Unit 2)	Structural integrity (attached) Direct flow	Stainless steel	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	C
Feedwater j-nozzle (Unit 2)	Structural integrity (attached) Direct flow	Stainless steel	Treated water (int)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	C
Feedwater j-nozzle (Unit 2)	Structural integrity (attached) Direct flow	Stainless steel	Treated water >140°F (ext) Steam (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	C
Feedwater j-nozzle (Unit 2)	Structural integrity (attached) Direct flow	Stainless steel	Treated water >140°F (int)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	C
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 (int)	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
Feedwater nozzle	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	IV.D1.R-37	3.1-1, 061	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
Moisture separators (Unit 1)	Structural integrity (attached)	Carbon steel	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-161	3.1-1, 072	C
Moisture separators (Unit 1)	Structural integrity (attached)	Carbon steel	Treated water (ext) Steam (ext)	Wall thinning – FAC	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-49	3.1-1, 074	A
Moisture separators (Unit 2)	Structural integrity (attached)	Stainless steel	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	C
Moisture separators (Unit 2)	Structural integrity (attached)	Stainless steel	Treated water >140°F (ext) Steam (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	C
Primary heads	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)	IV.C2.R-431	3.1-1, 124	C
Primary heads	Pressure boundary	Carbon steel with stainless steel cladding	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.D1.RP-232	3.1-1, 033	C
Primary heads	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-436	3.1-1, 127	A
Primary heads	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	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**
Primary inlet and outlet nozzles	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)	IV.C2.R-431	3.1-1, 124	A
Primary inlet and outlet nozzles	Pressure boundary	Carbon steel with stainless steel cladding	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.D1.RP-232	3.1-1, 033	A
Primary inlet and outlet nozzles	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-436	3.1-1, 127	C
Primary inlet and outlet nozzles	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Primary instrument nozzles	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	A
Primary instrument nozzles	Pressure boundary	Nickel alloy	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Primary manway covers (Unit 1)	Pressure boundary	Carbon steel with nickel alloy diaphragm	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
Primary manway covers (Unit 1)	Pressure boundary	Carbon steel with nickel alloy diaphragm	Reactor coolant (int)	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	C
Primary manway covers (Unit 1)	Pressure boundary	Carbon steel with nickel alloy diaphragm	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Primary manway covers (Unit 2)	Pressure boundary	Carbon steel with stainless steel diaphragm	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 covers (Unit 2)	Pressure boundary	Carbon steel with stainless steel diaphragm	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.D1.RP-232	3.1-1, 033	A
Primary manway covers (Unit 2)	Pressure boundary	Carbon steel with stainless steel diaphragm	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	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
Recirculation nozzles and end caps (Unit 2)	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
Recirculation nozzles and end caps (Unit 2)	Pressure boundary	Carbon steel	Treated water (int)	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
Secondary instrument nozzles (Unit 1)	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	A
Secondary instrument nozzles (Unit 1)	Pressure boundary	Nickel alloy	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	C
Secondary instrument nozzles (Unit 1)	Pressure boundary	Nickel alloy	Treated water >140°F (ext) Steam (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	C
Secondary instrument nozzles (Unit 2)	Pressure boundary	Carbon steel	Treated water (int) Steam (int)	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
Secondary instrument nozzles (Unit 2)	Pressure boundary	Carbon steel	Treated water (int) Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	IV.D1.R-37	3.1-1, 061	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
Secondary instrument nozzles (Unit 2)	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
Secondary manway and handhole closure covers	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 manway and handhole closure covers (Unit 1)	Pressure boundary	Carbon steel	Treated water (int) Steam (int)	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
Secondary manway and handhole closure covers (Unit 1)	Pressure boundary	Carbon steel	Treated water (int) Steam (int)	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
Secondary manway and handhole closure covers (Unit 2)	Pressure boundary	Carbon steel with stainless steel diaphragm	Treated water (int) Steam (int)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	C
Secondary manway and handhole closure covers (Unit 2)	Pressure boundary	Carbon steel with stainless steel diaphragm	Treated water >140°F (ext) Steam (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	C
Stay cylinders (Unit 1)	Pressure boundary	Carbon steel with stainless steel cladding	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.D1.RP-232	3.1-1, 033	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
Stay cylinders (Unit 1)	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-436	3.1-1, 127	C
Stay cylinders (Unit 1)	Pressure boundary	Carbon steel with stainless steel cladding	Reactor coolant (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
Steam generator components with fatigue analysis	Pressure boundary	Carbon steel with stainless steel cladding Carbon steel with nickel alloy cladding Nickel alloy Stainless steel	Reactor coolant (int)	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 generator components: external surfaces	Pressure boundary Mechanical closure	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
Steam outlet nozzle (Unit 2)	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
Steam outlet nozzle (Unit 2)	Pressure boundary	Carbon steel	Steam (int)	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
Steam outlet nozzle (Unit 2)	Pressure boundary	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	IV.D1.R-37	3.1-1, 061	A
Steam outlet nozzle venturis (Unit 2)	Throttle	Nickel alloy	Steam (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	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**
Steam outlet nozzle venturis (Unit 2)	Throttle	Nickel alloy	Steam (ext)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	C
Steam outlet nozzle with integral flow orifices (Unit 1)	Pressure boundary Throttle	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
Steam outlet nozzle with integral flow orifices (Unit 1)	Pressure boundary Throttle	Carbon steel	Steam (int)	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
Steam outlet nozzle with integral flow orifices (Unit 1)	Pressure boundary Throttle	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	IV.D1.R-37	3.1-1, 061	A
Tube bundle wrapper and wrapper supports	Structural support	Carbon steel	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-161	3.1-1, 072	A
Tube plugs	Pressure boundary	Nickel alloy	Reactor coolant (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-40	3.1-1, 070	A
Tube plugs	Pressure boundary	Nickel alloy	Reactor coolant (ext)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	C
Tube stabilizers (stakes) (Unit 2)	Structural support	Nickel alloy	Reactor coolant (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-40	3.1-1, 070	C
Tube stabilizers (stakes) (Unit 2)	Structural support	Nickel alloy	Reactor coolant (ext)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	C
Tube stabilizers (stakes) (Unit 2)	Structural support	Stainless steel	Reactor coolant (ext)	Cracking	Water Chemistry (B.2.3.2)	IV.D1.RP-17	3.1-1, 086	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**
Tube support lattice bars (Unit 1)	Structural support	Stainless steel	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10)	IV.D1.RP-225	3.1-1, 076	A
Tube support lattice bars (Unit 1)	Structural support	Stainless steel	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	A
Tube support lattice bars (Unit 1)	Structural support	Stainless steel	Treated water >140°F (ext) Steam (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	A
Tube support plates and anti-vibration bars (Unit 2)	Structural support	Stainless steel	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10)	IV.D1.RP-225	3.1-1, 076	A
Tube support plates and anti-vibration bars (Unit 2)	Structural support	Stainless steel	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-226	3.1-1, 071	A
Tube support plates and anti-vibration bars (Unit 2)	Structural support	Stainless steel	Treated water >140°F (ext) Steam (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-384	3.1-1, 071	A
Tubesheets	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.RP-161	3.1-1, 072	C
Tubesheets	Pressure boundary	Carbon steel with nickel alloy cladding	Reactor coolant (int)	Loss of material	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-436	3.1-1, 127	A
Upper and lower shells, secondary head, 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 shells, secondary head, transition cone	Pressure boundary	Carbon steel	Treated water (int) Steam (int)	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
Upper vessel clevises and shear keys	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
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Reactor coolant (int)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-44	3.1-1, 070	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Reactor coolant (int)	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 (int)	Loss of material	Water Chemistry (B.2.3.2)	IV.C2.RP-23	3.1-1, 088	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water (ext) Steam (ext)	Loss of material	Steam Generators (B.2.3.10)	IV.D1.RP-233	3.1-1, 077	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water (ext) Steam (ext)	Reduction of heat transfer	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-407	3.1-1, 111	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water >140°F (ext) Steam (ext)	Cracking	Steam Generators (B.2.3.10)	IV.D1.R-437	3.1-1, 125	A
U-tubes	Pressure boundary Heat transfer	Nickel alloy	Treated water >140°F (ext) Steam (ext)	Cracking	Steam Generators (B.2.3.10) Water Chemistry (B.2.3.2)	IV.D1.R-47	3.1-1, 069	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

1. Per further evaluation 3.1.2.2.11.1 the Unit 2 divider plates are fabricated from non-susceptible materials and do not require further aging management.

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.

- Containment Cooling (2.3.2.1)
- Containment Spray (2.3.2.2)
- Containment Isolation Components (2.3.2.3)
- Safety Injection (2.3.2.4)
- Containment Post-Accident Monitoring (2.3.2.5)

3.2.2 Results

Table 3.2.2-1, Containment Cooling – Summary of Aging Management Evaluation

Table 3.2.2-2, Containment Spray – Summary of Aging Management Evaluation

Table 3.2.2-3, Containment Isolation Components – Summary of Aging Management Evaluation

Table 3.2.2-4, Safety Injection – Summary of Aging Management Evaluation

Table 3.2.2-5, Containment Post-Accident Monitoring – Summary of Aging Management Evaluation

3.2.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.2.2.1.1 Containment Cooling

Materials

The materials of construction for the containment cooling system components are:

- Carbon steel
- Copper alloy
- Elastomer
- Galvanized steel
- Stainless steel
- Steel

Environments

The containment cooling system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the containment cooling system require management:

- Cracking
- Flow blockage
- Hardening or loss of strength
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the containment cooling 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.2.3.24)

3.2.2.1.2 Containment Spray

Materials

The materials of construction for the containment spray system components are:

- Aluminum
- Carbon steel
- Carbon steel with stainless steel cladding
- Coating
- Fiberglass reinforced vinyl ester
- Glass
- Gray cast iron
- Nickel alloy
- Stainless steel
- Steel

Environments

The containment spray system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Gas
- Treated borated water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the containment spray system require management:

- Cracking
- Delamination
- Flow blockage
- 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 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.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.2.2.1.3 Containment Isolation Components

Materials

The materials of construction for the containment isolation system components are:

- Carbon steel
- Copper alloy >15% Zn
- Stainless steel

Environments

The containment isolation 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 isolation system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the containment isolation 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.2.3.24)

3.2.2.1.4 Safety Injection

Materials

The materials of construction for the safety injection system components are:

- Carbon steel
- Carbon steel with stainless steel cladding
- Copper alloy >15% Zn
- 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
- Gas
- 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)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.2.2.1.5 Containment Post-Accident Monitoring

Materials

The materials of construction for the containment post-accident monitoring system components are:

- Carbon steel
- Stainless steel

Environments

The containment post-accident monitoring 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 post-accident monitoring system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the containment post-accident monitoring 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 (B.2.3.24)

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 <u>Cumulative Fatigue Damage</u>

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 Feature components, as described in SRP-SLR Item 3.2.2.2.1, is addressed in Section 4.3.2, "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. 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.

Insulated and non-insulated SS or nickel alloy bolting, piping, piping components, a tank, and heat exchanger components are exposed to an uncontrolled indoor air or outdoor air environment at PSL. A review of PSL OE confirms halides are potentially present in both the indoor and outdoor environments at PSL. 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 SS components exposed to uncontrolled indoor and outdoor air 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.2.3.24) 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. Conditions will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Bolting Integrity, Outdoor and Large Atmospheric Metallic Storage Tanks, External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are described in sections B.2.3.9, B.2.3.17, B.2.3.23, and B.2.3.24 respectively.

3.2.2.2.3 Loss of Material Due to General Corrosion and Flow Blockage Due to Fouling

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 PSL 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.

Insulated and non-insulated SS bolting, piping, piping components, a tank, and heat exchanger components are exposed to an uncontrolled indoor air and outdoor air environment at PSL. A review of PSL OE confirms halides are potentially present in the indoor environments at PSL. 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 SS components exposed to uncontrolled indoor air and outdoor 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.2.3.24) 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. Conditions will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Bolting Integrity, Outdoor and Large Atmospheric Metallic Storage Tanks, External Surfaces Monitoring of Mechanical Components, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are described in Sections B.2.3.9, B.2.3.17, B.2.3.23, and B.2.3.24, 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 OE 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.

PSL OE 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 in the Engineered Safety Features systems; therefore, recurring internal corrosion is not an applicable aging effect at PSL. There is no need to augment the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) 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.

A review of PSL OE confirms halides are potentially present in the environments at PSL. As such, all aluminum components exposed to outdoor 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) AMP. This AMP provides for the management of aging effects through periodic visual inspection. Any visual evidence of cracking will be evaluated for acceptability. Conditions will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is described in Section B.2.3.17.

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.*

There are no steel or stainless steel piping or piping components exposed to concrete in the Engineered Safety Features systems. Loss of material of the Unit 2 stainless steel refueling water tank exposed to concrete is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks AMP (Section B.2.3.17).

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 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) 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.

A review of PSL OE confirms halides are potentially present in the environments at PSL. As such, all aluminum components exposed to indoor uncontrolled air or outdoor air in the Engineered Safety Features Systems are susceptible to loss of material 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) 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. Conditions will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is described in Section B.2.3.17.

3.2.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Engineered Safety Feature 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 AMPs 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 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 the Engineered Safety Feature 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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / 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)	Consistent with NUREG-2191. Cumulative fatigue damage is an aging effect assessed by a fatigue TLAA. Further evaluation is documented in Section 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 program will be used to manage loss of material of stainless steel and nickel alloy piping, piping components, and heat exchanger components exposed to air. Further evaluation is documented in Section 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 applicable. 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	Not applicable. 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 / 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 stainless steel heat exchanger components and stainless steel and CASS components in the Reactor Vessels, Internals, and Reactor Coolant System. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring of Mechanical Components AMPs are used to manage cracking of stainless steel and CASS piping, piping components, pump casings, and heat exchanger components exposed to air internally and externally, respectively. Line item 3.2-1, 103 is used to manage cracking of the stainless steel refueling water tank. Further evaluation is documented in Section 3.2.2.2.4.
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	Consistent with NUREG-2191. The Boric Acid Corrosion (B.2.3.4) AMP is used to manage loss of material copper alloy >15% Zn piping components exposed to air with borated water leakage in the Engineered Safety Features Systems.
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 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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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	Consistent with NUREG-2191. This item applies to components in the Auxiliary Systems. The Thermal Embrittlement of Cast Austenitic Stainless Steel AMP is used to manage loss of fracture toughness of CASS components exposed to treated borated water with temperatures greater than 250°C (482°F).
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 PSL's Flow-Accelerated Corrosion AMP.
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 AMP is used to manage loss of material of stainless steel and steel closure bolting exposed to 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 AMP is used to manage loss of preload of metallic closure bolting in any environment.
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 under the scope of the Closed Treated Water Systems AMP.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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	Consistent with NUREG-2191 The Water Chemistry and One-Time Inspection AMPs are used to manage aluminum vortex breakers exposed to treated borated water.
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. The Water Chemistry and One-Time Inspection AMPs are used to manage reduction of heat transfer of stainless steel heat exchanger tubes exposed to treated borated water.
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. This line item is also used for stainless steel heat exchanger components. The Water Chemistry and One-Time Inspection AMPs are used to manage cracking of stainless steel heat exchangers, tanks, 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. The Water Chemistry and One-Time Inspection AMPs are used to manage loss of material of stainless steel heat exchanger components, piping, and piping components, and heat exchangers exposed to treated water or treated borated water.
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 / 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 heat exchanger 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. The Closed Treated Water Systems 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 / 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. The Closed Treated Water Systems AMP is 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	Consistent with NUREG-2191. The Closed Treated Water Systems AMP is used to manage loss of material in copper alloy heat exchanger components exposed to treated 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. The Closed Treated Water Systems AMP is used to manage reduction of heat transfer in stainless steel and copper alloy heat exchanger tubes exposed to treated water.
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	Consistent with NUREG-2191. The Selective Leaching AMP is used to manage loss of material copper alloy >15% Zn heat exchanger components exposed to 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 for heat exchanger components. The Selective Leaching AMP is used to manage loss of material due to selective leaching in gray cast iron heat exchangers 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 / TLAA	Further Evaluation Recommended	Discussion
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 exposed to closed-cycle cooling water or treated water 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 exposed to soil 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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage hardening or loss of strength due to elastomer degradation in elastomer piping and piping components exposed to air.
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 AMP is used to manage loss of material in steel external surfaces exposed to 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 used. There are no aluminum piping, piping components exposed to air or condensation in the Engineered Safety Features Systems. The Unit 1 refueling water tank is aluminum and is addressed by line item 3.2-1, 105.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage hardening or loss of strength due to elastomer degradation in steel piping and piping components exposed air.
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 AMP is used to manage loss of material internal to steel piping, piping components, tanks, ducting, and ducting components exposed to uncontrolled indoor air.
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.
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 used. Steel components that may be exposed to condensation internally are assumed to be exposed to air and are addressed by line item 3.2-1, 044.
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.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program / 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 AMP is used to manage loss of material of stainless steel, steel with stainless steel classing, and nickel alloy piping and piping components exposed to air internally. Further evaluation is documented in Section 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	Not applicable. There are no steel piping and piping components exposed to lubricating 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	Not applicable. There is no copper alloy or stainless steel piping and piping 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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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.
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 steel components exposed to soil, concrete, or underground.
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 stainless steel or nickel alloy piping components exposed to soil or concrete. The Unit 2 refueling water tank is addressed by line item 3.2-1, 067 and managed by the Outdoor and Large Atmospheric Metallic Storage Tanks AMP.
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.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 used. Aluminum components exposed to air are addressed by line item 3.2-1, 105.
3.2-1, 057	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for copper alloy piping and piping components. Ammonia-based compounds cannot accumulate inside of piping and piping components, so cracking is not an applicable aging effect for internal surfaces.
3.2-1, 058	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 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	Consistent with NUREG-2191. This line item is used for components in the Auxiliary Systems. There are no aging effects that require managing for galvanized steel ducting, ducting components, piping, or piping components 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 / TLAA	Further Evaluation Recommended	Discussion
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.
3.2-1, 062	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.
3.2-1, 063	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191 for components exposed to gas. Stainless steel and steel with stainless steel cladding piping and piping components exposed to gas do not have any aging effects that require management. Not used for stainless steel exposed to air with borated water leakage. Boric acid corrosion is not an applicable aging effect in stainless steel; the associated NUREG-2191 aging items are not used.
3.2-1, 064	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Not applicable. There are no steel components exposed to gas in the Engineered Safety Features System.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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. Based on a review of PSL OE, there are no instances of recurring internal corrosion in the Engineered Safety Features Systems.
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 with exception. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage cracking of the stainless steel refueling water tank 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.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 Outdoor and Large Atmospheric Metallic Storage Tanks.
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 with exception. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage loss of material of the stainless steel and aluminum refueling water tanks exposed to treated borated water.
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.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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, lubricating oil, condensation	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 AMP is used to manage loss of coating or lining integrity for the Unit 1 Refueling Water Tank.
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, condensation	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, treated borated water, or condensation.
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.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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 used. The Unit 1 aluminum refueling water tank sits above-ground on concrete. However, the aluminum tank bottom does not perform a pressure boundary function of the tank so does not require AMR. The Unit 2 stainless steel refueling water tank sits 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 AMP is used to manage cracking of stainless steel closure bolting exposed to air.
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.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. This line item is used for components in the Auxiliary Systems. The External Surfaces Monitoring of Mechanical Components AMP is used to manage reduction of heat transfer due to fouling for heat exchanger components exposed to air.
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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage reduced thermal insulation resistance due to moisture intrusion for non-metallic insulation not contained in type-1 penetrations. This line item is used to evaluate structural items in Section 3.5.
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 water or treated borated water that are susceptible to long-term loss of material. There are no Engineered Safety Features System components exposed to raw water.
3.2-1, 091	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Not applicable. There are no stainless steel piping and piping components exposed to concrete in the Engineered Safety Features Systems The stainless steel refueling water tank is addressed using different line items (3.2-1, 067 and 3.2-1, 129).

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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.
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)	Not used. Loss of material of stainless steel tanks is addressed under line items 3.2-1, 004 and 3.2-1, 106.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 used. The Engineered Safety Features Systems do not include any aluminum piping, piping components, or tanks exposed to raw water or waste water. Aluminum tanks exposed to air are addressed by line item 3.2-1, 102.
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 used. The Engineered Safety Features Systems do not include any aluminum piping, piping components exposed to air. Aluminum tanks exposed to air are listed under line item 3.2-1, 102.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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)	Consistent with NUREG-2191 with exception. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage cracking of the aluminum refueling water tank exposed to outdoor air. Further evaluation is documented in Section 3.2.2.2.8.
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 with exception. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to Manage cracking of the stainless steel refueling water tank exposed to air. Further evaluation is documented in Section 3.2.2.2.4.
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 aluminum Unit 1 refueling water tank is exposed to concrete but the tank bottom pressure boundary is formed by the fiberglass reinforced vinyl ester epoxy. Therefore, the aluminum tank boundary is not subject to AMR.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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)	Consistent with NUREG-2191 with exception. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage loss of material of the aluminum refueling water tank exposed to air. Further evaluation is documented in Section 3.2.2.2.10.
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 with exception. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage loss of material of the stainless steel refueling water tank exposed to air. Further evaluation is documented in Section 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 / 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 AMP is used to manage loss of material of insulated stainless steel piping exposed to air. Further evaluation is documented in Section 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 AMP is used to manage cracking of insulated stainless steel piping exposed to air. Further evaluation is documented in Section 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 / 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 underground 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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 underground aluminum piping, piping components, or tanks.
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 addressed by 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.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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.
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.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 used. The Engineered Safety Features Systems do not include any aluminum piping, piping components, or tanks exposed to soil. Aluminum tanks exposed to concrete are listed under line item 3.2-1, 104.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / 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 exposed to raw water or waste water.
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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material of elastomer piping and piping components exposed to air.
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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material of elastomer piping and piping components exposed to air.
3.2-1, 124	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not used. Boric acid corrosion is not an applicable aging effect for aluminum; the associated NUREG-2191 aging items are not used.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program / 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 with exception. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage loss of material of the stainless steel refueling water tank 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.
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 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 / TLAA**	**Further Evaluation Recommended**	**Discussion**
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: Containment 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)	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
Damper housing	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
Damper housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Drip pan	Direct flow	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
Drip pan	Direct flow	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: Containment 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**
Drip pan	Direct flow	Stainless steel	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3-1, 095	A
Duct	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	A
Duct	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	None	None	VII.J.AP-13	3.3-1, 116	A
Flex connection	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.EP-59	3.2-1, 038	A
Flex connection	Pressure boundary	Elastomer	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-465	3.2-1, 122	A
Flex connection	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D1.E-427	3.2-1, 043	A
Flex connection	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D1.E-466	3.2-1, 123	A

Table 3.2.2-1: Containment 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 (containment fan 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.2.3.24)	VII.C1.A-419	3.3-1, 096a	C
Heat exchanger (containment fan cooler headers and end caps)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	V.F.EP-10	3.2-1, 057	A
Heat exchanger (containment fan cooler headers and end caps)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-94	3.2-1, 032	A
Heat exchanger (containment fan cooler housing)	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 (containment fan cooler housing)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	C
Heat exchanger (containment fan cooler tubes)	Heat transfer	Copper alloy	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-419	3.3-1, 096a	A
Heat exchanger (containment fan cooler tubes)	Heat transfer	Copper alloy	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	V.A.EP-100	3.2-1, 033	A

Table 3.2.2-1: Containment 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 (containment fan cooler tubes)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	V.F.EP-10	3.2-1, 057	C
Heat exchanger (containment fan cooler tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-94	3.2-1, 032	A
Heat exchanger (containment fan cooler vent plug)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-93	3.2-1, 031	A
Heat exchanger (containment fan cooler vent plugs and frame side plates)	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 (containment fan cooler vent plugs and frame side plates)	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
Heat exchanger (Unit 1 containment fan cooler stubs and flanges)	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 (Unit 1 containment fan cooler stubs and flanges)	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	A
Heat exchanger (Unit 1 containment fan motor 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.2.3.24)	VII.C1.A-419	3.3-1, 096a	C

Table 3.2.2-1: Containment 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 (Unit 1 containment fan motor cooler header)	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 (Unit 1 containment fan motor cooler header)	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	A
Heat exchanger (Unit 1 containment fan motor cooler housing)	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	C
Heat exchanger (Unit 1 containment fan motor cooler housing)	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	None	None	VII.J.AP-13	3.3-1, 116	C
Heat exchanger (Unit 1 containment fan motor cooler tubes)	Heat transfer	Copper alloy	Air – indoor uncontrolled (ext)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-419	3.3-1, 096a	A
Heat exchanger (Unit 1 containment fan motor cooler tubes)	Heat transfer	Copper alloy	Treated water (int)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	V.A.EP-100	3.2-1, 033	A
Heat exchanger (Unit 1 containment fan motor cooler tubes)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	V.F.EP-10	3.2-1, 057	C
Heat exchanger (Unit 1 containment fan motor cooler tubes)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-94	3.2-1, 032	A

Table 3.2.2-1: Containment 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 (Unit 2 containment fan cooler CCW flange)	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 (Unit 2 containment fan cooler CCW flange)	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	A
Heat exchanger (Unit 2 containment fan cooler CCW flange)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	V.F.EP-10	3.2-1, 057	C
Heat exchanger (Unit 2 containment fan cooler CCW flange)	Pressure boundary	Copper alloy	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-94	3.2-1, 032	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
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
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	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D1.EP-103d	3.2-1, 007	A

Table 3.2.2-1: Containment 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
Thermowell	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D1.EP-81c	3.2-1, 048	A
Valve body (Unit 1 only)	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 (Unit 1 only)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

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	Carbon steel	Air – outdoor (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 – outdoor (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
Bolting	Mechanical closure	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity (B.2.3.9)	V.E.E-421	3.2-1, 079	A
Bolting	Mechanical closure	Stainless steel	Air – outdoor (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 – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	V.E.EP-116	3.2-1, 015	A
Eductor (Unit 1 only)	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 (Unit 1 only)	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 (Unit 1 only)	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	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
Heat exchanger (Unit 1 containment spray pump cooler 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 (Unit 1 containment spray pump cooler shell)	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	A
Heat exchanger (Unit 1 containment spray pump cooler shell)	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 (Unit 1 containment spray pump cooler 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.A.E-20	3.2-1, 019	A
Heat exchanger (Unit 1 containment spray pump cooler 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	A
Heat exchanger (Unit 1 containment spray pump cooler 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.A.EP-41	3.2-1, 022	A
Heat exchanger (Unit 1 containment spray pump cooler tubes)	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	A
Heat exchanger (Unit 2 containment spray pump cooler 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 (Unit 2 containment spray pump cooler shell)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.A.EP-92	3.2-1, 030	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
Heat exchanger (Unit 2 containment spray pump cooler 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.A.E-20	3.2-1, 019	A
Heat exchanger (Unit 2 containment spray pump cooler 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	A
Heat exchanger (Unit 2 containment spray pump cooler 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.A.EP-41	3.2-1, 022	A
Heat exchanger (Unit 2 containment spray pump cooler tubes)	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	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.2.3.24)	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.2.3.24)	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.2.3.24)	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.2.3.24)	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	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)	V.C.EP-63	3.2-1, 022	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	A
Orifice	Throttle	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	A
Piping	Pressure boundary	Nickel alloy	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	Nickel alloy	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-81c	3.2-1, 048	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	Pressure boundary	Nickel alloy	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-279	3.3-1, 095	A
Piping	Pressure boundary	Nickel alloy	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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)	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	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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.2.3.24)	V.A.EP-81c	3.2-1, 048	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (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 – outdoor (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	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	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	Pressure boundary	Stainless steel	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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.2.3.24)	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)	V.A.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	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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.2.3.24)	V.A.EP-81c	3.2-1, 048	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.A.EP-41	3.2-1, 022	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.2.3.24)	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.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1
Pump casing (containment spray)	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
Pump casing (containment spray)	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 (containment spray)	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	A
Pump casing (Unit 2 hydrazine)	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
Pump casing (Unit 2 hydrazine)	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 (Unit 2 hydrazine)	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	A
Rupture disk	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
Rupture disk	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
Rupture disk	Pressure boundary	Stainless steel	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A
Sight glass (Unit 1 only)	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
Sight glass (Unit 1 only)	Pressure boundary	Carbon steel with stainless steel cladding	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-103d	3.2-1, 007	A
Sight glass (Unit 1 only)	Pressure boundary	Carbon steel with stainless steel cladding	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-81c	3.2-1, 048	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**
Sight glass (Unit 1 only)	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	A
Sight glass (Unit 1 only)	Pressure boundary	Glass	Air – indoor uncontrolled (ext)	None	None	V.F.EP-15	3.2-1, 060	A
Sight glass (Unit 1 only)	Pressure boundary	Glass	Treated water (int)	None	None	V.F.EP-29	3.2-1, 060	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
Strainer	Filter	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-103d	3.2-1, 007	A
Strainer	Filter	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-81c	3.2-1, 048	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)	V.A.EP-41	3.2-1, 022	A
Strainer	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
Strainer	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
Strainer	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-103d	3.2-1, 007	A
Strainer	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-81c	3.2-1, 048	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**
Tank (Unit 1 NaOH storage)	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
Tank (Unit 1 NaOH storage)	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
Tank (Unit 1 NaOH storage)	Pressure boundary	Stainless steel	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A
Tank (Unit 1 NaOH storage)	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	A
Tank (Unit 1 refueling water)	Pressure boundary	Aluminum	Air – outdoor (ext)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-445a	3.2-1, 102	B
Tank (Unit 1 refueling water)	Pressure boundary	Aluminum	Air – outdoor (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-448a	3.2-1, 105	B
Tank (Unit 1 refueling water)	Pressure boundary	Aluminum	Air – outdoor (int)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-445a	3.2-1, 102	B
Tank (Unit 1 refueling water)	Pressure boundary	Aluminum	Air – outdoor (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-448a	3.2-1, 105	B
Tank (Unit 1 refueling water)	Pressure boundary	Aluminum	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	B
Tank (Unit 1 refueling water)	Pressure boundary	Coating	Air – indoor outdoor (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.D.A-416	3.3-1, 138	A
Tank (Unit 1 refueling water)	Pressure boundary	Coating	Treated borated 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)	V.A.E-401	3.2-1, 072	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
Tank (Unit 1 refueling water)	Pressure boundary	Fiberglass reinforced vinyl ester	Concrete (ext)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	-	-	F, 2
Tank (Unit 1 refueling water)	Pressure boundary	Fiberglass reinforced vinyl ester	Concrete (ext)	Delamination	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	-	-	F, 2
Tank (Unit 1 refueling water)	Pressure boundary	Fiberglass reinforced vinyl ester	Treated borated water (int)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	-	-	F, 2
Tank (Unit 1 refueling water)	Pressure boundary	Fiberglass reinforced vinyl ester	Treated borated water (int)	Delamination	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	-	-	F, 2
Tank (Unit 2 hydrazine storage)	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
Tank (Unit 2 hydrazine storage)	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
Tank (Unit 2 hydrazine storage)	Pressure boundary	Stainless steel	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A
Tank (Unit 2 hydrazine storage)	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	A
Tank (Unit 2 refueling water)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-446a	3.2-1, 103	B
Tank (Unit 2 refueling water)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-449a	3.2-1, 106	B
Tank (Unit 2 refueling water)	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-446a	3.2-1, 103	B
Tank (Unit 2 refueling water)	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	V.D1.E-449a	3.2-1, 106	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
Tank (Unit 2 refueling water)	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	B
Tank (Unit 2 refueling water)	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	B
Tank (Unit 2 refueling water)	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	B
Thermowell	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
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	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.A.EP-103c	3.2-1, 007	A
Thermowell	Pressure boundary	Stainless steel	Air – outdoor (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.A.EP-41	3.2-1, 022	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)	V.C.EP-63	3.2-1, 022	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	Air – outdoor (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**
Valve body	Pressure boundary	Stainless steel	Air – outdoor (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	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	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.2.3.24)	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.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1
Vortex breaker	Vortex prevention	Aluminum	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D1.EP-71	3.2-1, 017	A
Vortex breaker	Vortex prevention	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	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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.
F. Material not in NUREG-2191 for this component.

Plant Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage the wall thinning due to erosion aging effect.
2. Fiberglass reinforced vinyl ester lines the aluminum bottom of the Unit 1 Refueling Water Tank and performs the pressure boundary function of the tank. Because the aluminum tank bottom does not perform the pressure boundary function of the tank, the fiberglass reinforced vinyl ester is assumed to be in contact with concrete. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP will manage cracking and delamination of this material as opposed to the ASME Section XI Inservice Inspection, IWB, IWC, and IWD AMP which managed aging effects of this material for original license renewal.

Table 3.2.2-3: Containment Isolation – Summary 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
Debris screen (Unit 1 only)	Filter	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
Debris screen (Unit 1 only)	Filter	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
Debris screen (Unit 1 only)	Filter	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-103d	3.2-1, 007	A
Debris screen (Unit 1 only)	Filter	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-81c	3.2-1, 048	A
Debris screen (Unit 2 only)	Filter	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
Debris screen (Unit 2 only)	Filter	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A

Table 3.2.2-3: Containment Isolation – Summary 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 (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.2.3.24)	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)	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 Mechanical Components (B.2.3.23)	V.C.EP-107b	3.2-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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.2.3.24)	V.A.EP-81c	3.2-1, 048	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.2.3.24)	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)	V.C.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.C.EP-107b	3.2-1, 004	A

Table 3.2.2-3: Containment Isolation – Summary 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 (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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.2.3.24)	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	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	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	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	V.F.EP-10	3.2-1, 057	A
Valve body	Pressure boundary	Copper alloy > 15% Zn	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	V.E.EP-38	3.2-1, 008	A
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.2.3.24)	V.A.EP-103d	3.2-1, 007	A

Table 3.2.2-3: Containment Isolation – Summary 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.2.3.24)	V.A.EP-81c	3.2-1, 048	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.2.2-4: 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**
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
Heat exchanger (high pressure safety injection pump cooler tube sheet)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-94	3.2-1, 032	A
Heat exchanger (high pressure safety injection pump cooler tube sheet)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	V.D1.EP-37	3.2-1, 034	A
Heat exchanger (high pressure safety injection pump cooler 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	A
Heat exchanger (high pressure safety injection pump cooler 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	A
Heat exchanger (high pressure safety injection pump cooler 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	A
Heat exchanger (high pressure safety injection pump cooler 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	A

Table 3.2.2-4: 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**
Heat exchanger (shutdown cooling channels and channel cover)	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
Heat exchanger (shutdown cooling channels and channel cover)	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	A
Heat exchanger (shutdown cooling channels and channel cover)	Pressure boundary	Carbon steel with stainless steel cladding	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	C
Heat exchanger (shutdown cooling 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 (shutdown cooling 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	A
Heat exchanger (shutdown cooling 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	A
Heat exchanger (shutdown cooling 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	A
Heat exchanger (shutdown cooling 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	A
Heat exchanger (shutdown cooling 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	C

Table 3.2.2-4: 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
Heat exchanger (shutdown cooling 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	A
Heat exchanger (shutdown cooling tubesheet)	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	A
Heat exchanger (shutdown cooling tubesheet)	Pressure boundary	Carbon steel with stainless steel cladding	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	C
Heat exchanger (shutdown cooling tubesheet)	Pressure boundary	Carbon steel with stainless steel cladding	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D1.EP-92	3.2-1, 030	A
Heat exchanger (Unit 1 high pressure safety injection pump cooler 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 (Unit 1 high pressure safety injection pump cooler 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	A
Heat exchanger (Unit 1 high pressure safety injection pump cooler 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	A
Heat exchanger (Unit 1 low pressure safety injection pump cooler 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 (Unit 1 low pressure safety injection pump cooler 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	A

Table 3.2.2-4: 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
Heat exchanger (Unit 1 low pressure safety injection pump cooler 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	A
Heat exchanger (Unit 1 low pressure safety injection pump cooler 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	A
Heat exchanger (Unit 1 low pressure safety injection pump cooler 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	A
Heat exchanger (Unit 1 low pressure safety injection pump cooler 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	A
Heat exchanger (Unit 1 low pressure safety injection pump cooler 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	C
Heat exchanger (Unit 1 low pressure safety injection pump cooler 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	A
Heat exchanger (Unit 2 high pressure safety injection pump cooler 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 (Unit 2 high pressure safety injection pump cooler 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	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

Table 3.2.2-4: 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	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	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	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	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	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	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

Table 3.2.2-4: 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	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	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	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 4.3.2, 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
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	A
Pump casing (high pressure safety injection)	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 3.2.2-4: 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 (high pressure safety injection)	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 (high pressure safety injection)	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	A
Pump casing (low pressure safety injection)	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 (low pressure safety injection)	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 (low pressure safety injection)	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	A
Pump casing (low pressure safety injection)	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	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 (safety injection)	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 (safety injection)	Pressure boundary	Carbon steel with stainless steel cladding	Gas (int)	None	None	V.F.EP-22	3.2-1, 063	A

Table 3.2.2-4: 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 (safety injection)	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	A
Tank (safety injection)	Pressure boundary	Carbon steel with stainless steel cladding	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	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
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	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	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

Table 3.2.2-4: 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	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	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	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.2.2-5: Containment Post-Accident Monitoring – Summary 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
Flexible hose	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
Flexible hose	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
Flexible hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-103d	3.2-1, 007	A
Flexible hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-81c	3.2-1, 048	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 Mechanical Components (B.2.3.23)	V.C.EP-107b	3.2-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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.2.3.24)	V.A.EP-81c	3.2-1, 048	A

Table 3.2.2-5: Containment Post-Accident Monitoring – Summary 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)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.C.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.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.2.3.24)	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.2.3.24)	V.A.EP-81c	3.2-1, 048	A
Sample vessel (Unit 1 only)	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
Sample vessel (Unit 1 only)	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
Sample vessel (Unit 1 only)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.EP-103d	3.2-1, 007	A
Sample vessel (Unit 1 only)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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	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.2.3.24)	V.A.EP-103d	3.2-1, 007	A

Table 3.2.2-5: Containment Post-Accident Monitoring – Summary 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.2.3.24)	V.A.EP-81c	3.2-1, 048	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with 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, which are addressed in this section are described in the indicated sections.

- Chemical Volume and Control (2.3.3.1)
- Component Cooling Water (2.3.3.2)
- Demineralized Makeup Water (2.3.3.3)
- Diesel Generator (2.3.3.4)
- Fire Protection and Service Water (2.3.3.5)
- Fuel Pool Cooling (2.3.3.6)
- Instrument Air / Miscellaneous Bulk Gas Supply (2.3.3.7)
- Intake Cooling Water / Emergency Cooling Canal (2.3.3.8)
- Primary Makeup Water (2.3.3.9)
- Sampling (2.3.3.10)
- Turbine Cooling Water (2.3.3.11)
- Ventilation (2.3.3.12)
- Waste Management (2.3.3.13)

3.3.2 Results

Table 3.3.2-1, Chemical Volume and Control – Summary of Aging Management Evaluation

Table 3.3.2-2, Component Cooling Water – Summary of Aging Management Evaluation

Table 3.3.2-3, Demineralized Makeup Water – Summary of Aging Management Evaluation

Table 3.3.2-4, Diesel Generators and Support Systems – Summary of Aging Management Evaluation

Table 3.3.2-5, Fire Protection / Service Water – Summary of Aging Management Evaluation

Table 3.3.2-6, Fuel Pool Cooling – Summary of Aging Management Evaluation

Table 3.3.2-7, Instrument Air / Miscellaneous Bulk Gas Supply – Summary of Aging Management Evaluation

Table 3.3.2-8, Intake Cooling Water / Emergency Cooling Canal – Summary of Aging Management Evaluation

Table 3.3.2-9, Primary Makeup Water – Summary of Aging Management Evaluation

Table 3.3.2-10, Sampling – Summary of Aging Management Evaluation

Table 3.3.2-11, Turbine Cooling Water – Summary of Aging Management Evaluation

Table 3.3.2-12, Ventilation – Summary of Aging Management Evaluation

Table 3.3.2-13, Waste Management – 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 Volume and Control

Materials

The materials of construction for the chemical and volume control system components are:

- Carbon steel
- CASS
- Stainless steel

Environments

The chemical and volume control system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Gas
- Treated borated water
- Treated borated water >140°F
- Treated borated water >482°F
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the chemical and volume control system 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 chemical and volume control system components:

- Bolting Integrity (B.2.3.9)
- Boric Acid Corrosion (B.2.3.4)
- 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)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- 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)

3.3.2.1.2 Component Cooling Water

Materials

The materials of construction for the CCW system components are:

- Carbon steel
- Coating
- Copper alloy > 8% Al
- Copper alloy > 15% Zn
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environments

The CCW system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Raw water
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the CCW 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 CCW 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.2.3.24)
- 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)

3.3.2.1.3 Demineralized Makeup Water

Materials

The materials of construction for the DW system components are:

- Carbon steel
- Stainless steel

Environments

The DW system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the DW system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the DW 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)

3.3.2.1.4 Diesel Generators and Support Systems

Materials

The materials of construction for the emergency diesel generator system components are:

- Aluminum
- Carbon steel
- Coating
- Copper alloy
- Copper alloy >15% Zn
- Glass
- Gray cast iron
- Plexiglas
- Polyester
- Rubber
- Stainless steel

Environments

The emergency diesel generator system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Diesel exhaust
- Fuel oil
- Lubricating oil
- Treated water
- Underground

Aging Effects Requiring Management

The following aging effects associated with the emergency diesel generator system require management:

- Cracking
- Cumulative fatigue damage
- Hardening or loss of strength
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the emergency diesel generator 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.2.3.24)
- Internal Coatings/Lining for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Outdoor and Large Atmospheric Metallic Storage Tank (B.2.3.17)
- Selective Leaching (B.2.3.21)

3.3.2.1.5 Fire Protection/ Service Water

Materials

The materials of construction for the fire protection and service water system components are:

- Aluminum
- Carbon steel
- Cast iron
- Coating
- Coating (cementitious)
- Copper alloy
- Copper alloy > 15% Zn
- Ductile iron
- Fiberglass
- Galvanized steel
- Glass
- Gray cast iron
- PVC/CPVC
- Stainless steel
- Steel

Environments

The fire protection and service water system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage

- Concrete
- Gas
- Lubricating oil
- Raw water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the fire protection and service water systems require management:

- Blistering
- Cracking
- Flow blockage
- 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 and 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 Protection (B.2.3.15)
- Fire Water System (B.2.3.16)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)

3.3.2.1.6 Fuel Pool Cooling

Materials

The materials of construction for the fuel pool cooling system components are:

- Carbon steel
- Stainless steel

Environments

The fuel pool cooling 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 fuel pool cooling 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 fuel pool cooling 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)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.3.2.1.7 Instrument Air and Miscellaneous Bulk Gas Supply

Materials

The materials of construction for the instrument air and bulk gas system components are:

- Aluminum
- Carbon steel
- Copper alloy
- Copper alloy >15% Zn
- Elastomer
- Galvanized steel
- Glass
- Stainless steel
- Steel

Environments

The instrument air and bulk gas system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Gas

Aging Effects Requiring Management

The following aging effects associated with the instrument air instrument air and bulk gas system require management:

- Cracking
- Hardening or loss of strength
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the instrument air and bulk gas 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.2.3.24)

3.3.2.1.8 Intake Cooling Water/ Emergency Cooling Canal

Materials

The materials of construction for the ICW and ECC system components are:

- Carbon steel
- Coating
- Coating (cementitious)
- Copper alloy
- Copper alloy > 8% Al
- Copper alloy > 15% Zn
- Elastomer
- Fiberglass
- Gray cast iron
- Monel
- Stainless steel

Environments

The ICW and ECC system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Raw water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the ICW and ECC 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 ICW and ECC 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)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- 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)

3.3.2.1.9 Primary Makeup Water

Materials

The materials of construction for the PMW system components are:

- Carbon steel
- Coating

- Copper alloy
- Elastomer
- Nickel alloy
- Stainless steel

Environments

The PMW system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Soil
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the PMW system require management:

- Cracking
- Hardening or loss of strength
- Loss of coating or lining integrity
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the PMW 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)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Lining 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)

3.3.2.1.10 Sampling

Materials

The materials of construction for the sampling system components are:

- Carbon steel
- CASS
- Stainless steel

Environments

The 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 borated water >482°F

Aging Effects Requiring Management

The following aging effects associated with the sampling system require management:

- Cracking
- Loss of fracture toughness
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the 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)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- 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)

3.3.2.1.11 Turbine Cooling Water

Materials

The materials of construction for the turbine cooling water system components are:

- Carbon steel
- Coating
- Copper alloy > 15% Zn
- Glass
- Stainless steel

Environments

The turbine cooling water system components are exposed to the following environments:

- Air – indoor uncontrolled
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the turbine cooling water system require management:

- Cracking
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following AMPs manage the aging effects for the turbine cooling water 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.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Selective Leaching (B.2.3.21)

3.3.2.1.12 Ventilation

Materials

The materials of construction for the ventilation system components are:

- Aluminum
- Carbon steel
- Cast iron
- Copper alloy
- Ductile iron
- Elastomer
- Galvanized steel
- Stainless steel
- Steel

Environments

The ventilation system components are exposed to the following environments:

- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Underground

Aging Effects Requiring Management

The following aging effects associated with the ventilation system require management:

- Cracking
- Hardening or loss of strength
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the ventilation 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)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)

3.3.2.1.13 Waste Management

Materials

The materials of construction for the waste management system components are:

- Carbon steel
- Copper alloy
- Nickel alloy
- Stainless steel

Environments

The waste management system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Gas
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the waste management system require management:

- Cracking
- 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 management 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.2.3.24)
- One-Time Inspection (B.2.3.20)

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-2021-02- MECHANICAL.

3.3.2.2.1 <u>Cumulative Fatigue Damage</u>

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 System components, as described in SRP-SLR Item 3.2.2.2.1, is addressed as a TLAA in Section 4.3.2, "Metal Fatigue of Non-Class 1 Components."

3.3.2.2.2 <u>Cracking Due to Stress Corrosion Cracking and Cyclic Loading</u>

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 PSL OE, there is no evidence of cracking of nonregenerative heat exchanger tubes. This confirms the adequacy of the Water Chemistry (B.2.3.2) AMP as described in the above text from GALL-SLR. Consistent with the recommendation of NUREG-2191, the Water Chemistry (B.2.3.2) 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 SS 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 PSL OE confirms halides are potentially present in both the uncontrolled and outdoor environments at PSL. Additionally, insulated piping and components located in uncontrolled air, particularly those in standby or periodically operated systems, could conservatively see an accumulation of contaminants from water intrusion through or beneath insulation. As such, SS components exposed to uncontrolled indoor air 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.2.3.24), External Surfaces Monitoring of Mechanical Components (B.2.3.23), and Buried and Underground Piping and Tanks (B.2.3.27) AMPs 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 SS 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. Conditions 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, External Surfaces Monitoring of Mechanical Components, and Buried and Underground Piping and Tanks AMPs are described in Sections B.2.3.9, B.2.3.25, B.2.3.23, and B.2.3.27 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 SS bolting, piping, piping components, heat exchanger components, and tanks exposed to uncontrolled indoor air. A review of PSL OE confirms halides are potentially present in both the indoor and outdoor environments at PSL 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 SS 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.2.3.24), External Surfaces Monitoring of Mechanical Components (B.2.3.23), and Buried and Underground Piping and Tanks (B.2.3.27) 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. Conditions 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, External Surfaces Monitoring of Mechanical Components, and Buried and Underground Piping and Tanks AMPs are described in Sections B.2.3.9, B.2.3.24, B.2.3.23, and B.2.3.27 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 OE 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 does not lead to the conclusion that treated water and waste water systems have experienced recurring internal corrosion. However, site OE shows that carbon steel components exposed to raw water in the intake cooling water system have experienced recurring internal corrosion. The Open-Cycle Cooling Water System AMP is enhanced to manage loss of material due to recurring internal corrosion and details related to management of recurring internal corrosion are provided in AMP Section B.2.3.11.

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.

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, 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 PSL OE confirms halides are potentially present in the indoor environment at PSL. 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.2.3.24) 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. Conditions 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 and External Surfaces Monitoring of Mechanical Components AMPs are described in Sections B.2.3.24 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 SS piping and tanks exposed to concrete. A review of OE for PSL indicates there are occurrences of concrete degradation, in some systems, 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. It should be noted that some systems within the Auxiliary Systems have SS and steel components exposed to concrete but are located indoors and shielded from an outdoor environment.

Consistent with the recommendation of GALL-SLR, the Buried and Underground Piping and Tanks (B.2.3.27) AMP is 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. Conditions will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Buried and Underground Piping and Tanks AMP is described in Section B.2.3.27.

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 or outdoor air. A review of PSL OE confirms halides are potentially present in the indoor environments at PSL. 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.2.3.24) 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. Conditions 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 and External Surfaces Monitoring of Mechanical Components AMPs are described in Sections B.2.3.24 and B.2.3.23 respectively.

3.3.2.3 Time-Limited Aging Analysis

The TLAAs identified below are associated with the Auxiliary System 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 System 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 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 3.3-1: 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 Crane Load Cycle Limits TLAA is used to manage cumulative fatigue damage in steel cranes, bridges, structural members, and structural components exposed to any. This line item is used to evaluate structural items in Section 3.5.
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. The Water Chemistry 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.
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. Cracking of non-regenerative heat exchanger tubing is addressed by line item 3.3-1, 003.

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, 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 cylinders and flanges. The External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are used to manage cracking of stainless steel piping, piping components, heat exchanger cylinders and flanges, 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 cylinders and flanges. The External Surfaces Monitoring of Mechanical Components and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are used to manage external and internal loss of material of stainless steel piping, piping components, heat exchanger cylinders and flanges, 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 used. The spent fuel pool cooling pumps and boric acid makeup pumps are not high pressure pumps and are not subject to cracking due to cyclic loading. The charging pumps are not subject to high temperatures to cause them to be subject to fatigue cracking.
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 line items 3.3-1, 003 and 3.3-1, 020.

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, 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 components exposed to air with borated water leakage.
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 AMP is used to manage loss of material in steel, monel, and stainless steel closure bolting exposed to 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 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. The Water Chemistry and One-Time Inspection AMPs are used to manage reduction of heat transfer in stainless steel heat exchanger tubes 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, 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 line items 3.3-1, 028 and 3.3-1, 124.
3.3-1, 019	This line item only applies to BWRs.				
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. The Water Chemistry and One-Time Inspection 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 are no aluminum piping or piping components 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.				

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, 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. The Water Chemistry and One-Time Inspection 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, 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 in the Auxiliary Systems.
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	Consistent with NUREG-2191. The Open-Cycle Cooling Water System AMP is used to manage cracking, loss of material, and flow blockage in fiberglass piping and 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. The Open-Cycle Cooling Water System AMP is used to manage loss of material and flow blockage in copper alloy and monel 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. This line item is also used for heat exchanger components. The Open-Cycle Cooling Water System 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. The Open-Cycle Cooling Water System 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. The Open-Cycle Cooling Water System AMP is used to manage loss of material and flow blockage in stainless steel piping and piping 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. The Open-Cycle Cooling Water AMP is used to manage reduction of heat transfer for copper alloy heat exchanger tubes exposed to raw 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.
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.

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, 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. This line item has also been applied to heat exchanger components. The Closed Treated Water Systems AMP is used to manage the loss of material of steel piping, piping components, and heat exchanger components when exposed to treated 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. The Closed Treated Water Systems AMP is used to manage loss of material in steel and copper alloy heat exchanger components, piping, and piping components exposed to treated 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.
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. This line item has also been applied to heat exchanger components, including heat exchanger components in the reactor coolant system. The Closed Treated Water Systems AMP is used to manage the loss of material of stainless steel piping, piping components, and heat exchanger components 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, 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. The Closed Treated Water Systems AMP is used to manage reduction of heat transfer for stainless steel and copper heat exchanger tubes exposed to treated water.
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 credited boraflex components in the Auxiliary Systems.
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 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, or tanks exposed to condensation 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, 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 air. The Fire Protection AMP is used to manage hardening, loss of strength, and shrinkage of elastomer fire barriers exposed to 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. The Fire Protection AMP is used to manage loss of material of steel fire suppression system piping and piping components exposed to air.
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 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	Not applicable. There are no reinforced concrete structural fire barriers exposed to air in the Auxiliary Systems. Line item 3.5-1, 067 is used for reinforced concrete structural fire barriers.
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. The Fire Water System AMP is used to manage loss of material and flow blockage of steel fire hydrants exposed to 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, 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 AMP is used to manage loss of material and flow blockage of steel and copper alloy piping and piping components exposed to raw water.
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 AMP is used to manage loss of material and flow blockage of stainless steel piping and piping components exposed to raw 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 AMP. The Fuel Oil Chemistry and One-Time Inspection 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 AMP. The Fuel Oil Chemistry and One-Time Inspection AMPs are used to manage loss of material in steel piping, piping components, and tanks 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, 071	Stainless steel, aluminum, nickel 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 with the Fuel Oil Chemistry AMP. The Fuel Oil Chemistry and One-Time Inspection AMPs are used to manage loss of material in stainless steel piping and piping components exposed to fuel oil.
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 AMP is used to manage loss of material of gray cast iron, ductile iron, copper alloy > 8% Al, and copper alloy >15% Zn piping, piping components, and heat exchanger components exposed to raw water, treated 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 AMP is used to manage hardening or loss of strength of elastomer piping and piping components 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, 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 AMP is used to manage loss of material for steel external surfaces exposed to air.
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 AMP is used to manage loss of material for steel heat exchanger components exposed to 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 AMP is used to manage loss of material for elastomer and fiberglass piping components 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 AMP is used to manage cracking of stainless steel piping and piping components exposed to diesel engine exhaust.

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, 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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage hardening or loss of strength and flow blockage for elastomer piping, and piping components exposed to indoor uncontrolled air, treated water, or raw water.
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is used to manage loss of material and flow blockage for steel and stainless steel components exposed to 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.
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.

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, 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 AMP 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	Not applicable. There are no copper alloy piping and piping components exposed to raw water in the Auxiliary Systems.
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 or ducting components exposed to air or condensation that are associated with 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, 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 Systems.
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 AMP is used to manage loss of material and flow blockage in copper, nickel alloy and stainless steel piping and piping components exposed to waste water.
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 AMP is used to manage loss of material and flow blockage of elastomer expansion joints, piping, and piping components exposed to raw water, treated water, or 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, 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 is used to manage reduction of heat transfer in copper alloy heat exchanger tubes and fins 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 and One-Time Inspection 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 and One-Time Inspection AMPs are used to manage loss of material of steel heat exchanger components exposed to lubricating oil.
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 and One-Time Inspection AMPs are used to manage loss of material of aluminum 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 and One-Time Inspection AMPs are used to manage loss of material of stainless steel 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, 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 heat exchanger tubes 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	Consistent with NUREG-2191. The Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP is used to manage reduction of neutron-absorbing capacity, change in dimensions and loss of material due to effects of SFP environment. This line item is used to evaluate structural items in Section 3.5.
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 exposed to soil 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, 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	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP is used to manage loss of material in stainless steel piping, piping components exposed to soil or concrete
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. The Buried and Underground Piping and Tanks AMP is used to manage loss of material in stainless steel closure bolting exposed to soil.
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. The Buried and Underground Piping and Tanks AMP is used to manage loss of material in steel piping, piping components, and closure bolting exposed to soil or concrete that are subject to wetting.
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 Structures Monitoring (B.2.3.33) 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)	Consistent with NUREG-2191. There are no aging effects to be managed for steel piping and piping components exposed to concrete that are not subject to wetting. Further evaluation is documented in Section 3.2.2.2.9.

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, 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.
3.3-1, 114	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for copper piping and piping components exposed to gas or air that would affect the pressure boundary intended function. Ammonia-based compounds cannot accumulate inside of piping and piping components, so cracking is not an applicable aging effect for internal surfaces.
3.3-1, 115	Copper alloy, copper alloy (>8% Al) 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 copper alloy or copper alloy >8% Al components; the associated NUREG-2191 aging items are not used.
3.3-1, 116	Galvanized steel piping, piping components exposed to air – indoor uncontrolled	None	None	No	Consistent with NUREG-2191. This line item is also applied to heat exchanger components.

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, 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.
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 or PVC/CPVC exposed to air 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 for components exposed to gas. Stainless steel and steel with stainless steel cladding piping and piping components exposed to gas do not have any aging effects that require management. Not used for stainless steel exposed to air with borated water leakage. Boric acid corrosion is not an applicable aging effect in stainless steel; the associated NUREG-2191 aging items are not 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, 121	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for steel piping and piping components exposed to gas
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.
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. The Water Chemistry and One-Time Inspection 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, 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. This line item is also applied to stainless steel heat exchanger components, tanks, spent fuel storage and transfer components. The Water Chemistry and One-Time Inspection AMPs are used to manage loss of material of stainless steel components exposed to treated borated water.
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. The Fire Water System, Open-Cycle Cooling Water System, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are credited with managing wall thinning due to erosion of metallic components exposed to raw and waste water because the Flow-Accelerated Corrosion AMP scope is limited to high temperature and high flow treated water systems. Erosion is not an applicable aging effect in treated water or treated borated water environments 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, 127	Metallic piping, piping components, tanks exposed to 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)	Consistent with NUREG-2191. Based on plant specific OE, recurring internal corrosion is an applicable effect for carbon steel components in the intake cooling water system. The Open-Cycle Cooling Water System AMP is used to manage the loss of material due to recurring internal corrosion aging effect for carbon steel, components exposed to raw water in the intake cooling water system. Further evaluation is documented in Section 3.3.2.2.7.
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 with exception. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage loss of material in steel tanks exposed to uncontrolled air, outdoor air, and concrete.
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 AMP is used to manage loss of material and flow blockage in metallic sprinklers exposed to 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 AMP is used to manage flow blockage in spray nozzles exposed to air 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, 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 heat exchanger fins and tubes. The External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material of insulated steel piping and piping components along with cracking of copper alloy heat exchanger fins and tubes exposed to 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.
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 AMP is used to manage loss of material in steel and stainless steel piping and piping components 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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material of stainless steel pump casings 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, 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 steel vortex breakers. The Fire Water System AMP is used to manage loss of material in steel fire water storage tanks and vortex breakers exposed to uncontrolled air, concrete, 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 with exception. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage loss of material in steel tanks that are exposed to treated water in the Auxiliary Systems.
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, air – dry, air, condensation	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 and Fire Water AMPs are used to manage loss of coating or lining integrity for any material with a coating.

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, 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, air – dry, air, condensation	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 AMP is not used to manage loss of material.
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. Internal coatings / linings are not used to manage loss of material for components with internal coatings/linings in the Auxiliary Systems .
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 AMP is used to manage loss of material stainless steel, copper alloy, and monel closure bolts 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, 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. The Buried and Underground Piping and Tanks AMP is used to manage cracking for steel and stainless steel piping, piping components, and bolting exposed to soil or concrete.
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 AMP is used to manage cracking of stainless steel closure bolting exposed to indoor uncontrolled air, outdoor air, and soil.
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)	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP is used to manage loss of material of stainless piping exposed to an underground environment. Further evaluation is document in Section 3.3.2.2.3.
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 piping and piping components in the Auxiliary Systems exposed to outdoor air 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, 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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage cracking, blistering, and loss of material for fiberglass tanks exposed to air.
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 AMP is used to manage reduction in heat transfer in copper alloy heat exchanger components exposed to air.
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. Line items 3.2-1, 044 is used for steel piping and piping components exposed to air – outdoor internally.
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 used. There are monel piping, piping components exposed to raw water in the Auxiliary Systems, but they are managed by line items 3.3-1, 034 and 3.3-1, 126.

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, 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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material in fiberglass tanks exposed to air.
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. The Open-Cycle Cooling Water System, Closed Treated Water Systems and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are used to manage cracking in copper alloy components exposed to a treated water, or raw water environment. Additionally, the Fire Water Systems 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. There are no copper alloy heat exchanger components exposed to condensation in the Auxiliary Systems. Copper alloy heat exchangers exposed to air are included under line item 3.3-1, 096a.
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	Not applicable. There are no steel or copper alloy components exposed to a steam environment in the Auxiliary Systems.
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.
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 aging effects requiring manage for PVC components exposed to outdoor air because the components are not exposed to sunlight. This line item is used to evaluate structural items in Section 3.5.
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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage cracking and blistering in fiberglass tanks exposed to raw water.
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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material and flow blockage in fiberglass tanks exposed to a raw water 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, 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 exposed to soil 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 exposed to concrete 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	Not used. While there are fire barriers exposed to air, they are covered by line items 3.3-1, 267, 3.3-1, 268, and 3.3-1, 269.
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 used. Non-metallic thermal insulation is addressed by line item 3.2-1, 087.
3.3-1, 184	PVC piping, piping components, tanks exposed to concrete	None	None	No	Consistent with NUREG-2191. There are no aging effects requiring manage for PVC components exposed to concrete. This line item is used to evaluate structural items in Section 3.5.
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.

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, 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.
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 and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are used to manage cracking of aluminum components exposed to air. Further evaluation is documented in Section 3.3.2.2.8.

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, 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 AMP is used to manage long-term loss of material in steel components exposed to raw water and waste water. Long-term loss of material is not applicable for treated water systems material because corrosion inhibitors or water chemistry controls are used.
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.
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 water that require aging management 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, 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 in the Auxiliary Systems.
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	Not used. Other line items are used for loss of material of metallic piping, piping components, and heat exchanger components.
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	Not used. There is metallic piping, and piping components with only a leakage boundary (spatial) or structural integrity (attached) intended function in the fire water system, but they are addressed by line item 3.3-1, 134.

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, 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 AMP is used to manage loss of preload, loss of material, and cracking for steel components exposed to air. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 202	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.3.2.2.9)	Consistent with NUREG-2191. There are no aging effects that require management for stainless steel piping or piping components exposed to concrete in the waste disposal system and in the reactor cavity sump because they are not exposed to concrete that is regularly exposed to water. Further evaluation is documented in Section 3.3.2.2.9.
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 AMP is used to manage cracking of insulated stainless steel piping, piping components, tanks, and heat exchanger shells and channel heads exposed to air. 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, 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 applicable. There are no stainless steel and copper alloy heat exchanger tubes exposed to raw water in the Auxiliary System not covered by GL 89-13.
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 in the Auxiliary Systems.
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 that require aging management in the Auxiliary Systems.
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.

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, 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.
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.

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, 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)	Not used. Loss of material of stainless steel tanks exposed to air is addressed in line item 3.3-1, 006 and 3.3-1, 232.
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 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 applicable. 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 applicable. There are no stainless steel tanks in the Auxiliary Systems within the scope of the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks AMP.

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 in the Auxiliary Systems within the scope of the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks AMP.
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 in the Auxiliary Systems within the scope of the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks AMP.
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 applicable. There are no stainless steel tanks in the Auxiliary Systems within the scope of the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks AMP.

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 AMP is used to manage loss of material in insulated stainless steel piping, piping components, and heat exchanger shells and channel heads exposed to air. Further evaluation is documented in Section 3.3.2.2.4.
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 and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are used to manage loss of material in aluminum piping components exposed to air. Further evaluation is documented in Section 3.3.2.2.10.

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, 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. This line item is also used for tanks. The Compressed Air Monitoring AMP is used to manage loss of material in metallic piping, piping components, and tanks exposed to an internal dry air environment.
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.

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, 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)	Not used. Loss of material from stainless steel heat exchanger components exposed to indoor uncontrolled air is addressed by line items 3.3-1, 006 and 3.3-1, 232.

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 External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material of aluminum heat exchanger components exposed to 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)	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP is used to manage cracking of stainless steel piping components exposed to an underground environment. Further evaluation is documented in Section 3.3.2.2.4.
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. Boric acid corrosion is not an applicable aging effect for aluminum; the associated NUREG-2191 aging items are not 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, 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 AMP is used to manage loss of material of steel piping, piping components exposed to 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. Although the reactor cooling pump oil collection system internal environment is waste oil and not within the scope of the Lubricating Oil Analysis AMP, controls associated with the Lubricating Oil Analysis AMP are used for the RCPs to minimize contaminants that may be present in the RCP collection system. Therefore, the Lubricating Oil Analysis and One-Time Inspection 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.

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, 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	Not applicable. There is no plastic piping exposed to raw water, raw water (potable), treated water, or waste water in the Auxiliary Systems.
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)	Not used. Cracking of aluminum heat exchanger components exposed to air is managed by line item 3.3-1, 189.
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 AMP is used to manage loss of material for steel fire damper assemblies exposed to 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, 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 and One-Time Inspection 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 elastomer, fiberglass, HDPE piping, piping components exposed to waste water in the Auxiliary Systems. Metallic components exposed to waste water are addressed by line items 3.3-1, 091 and 3.3-1, 095.
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 AMP is used to manage loss of material in metallic HVAC bolting exposed to air.
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.

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, 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.
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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring of Mechanical Components AMPs are used to manage hardening or loss of strength, loss of material, and cracking of polyester or plexiglass piping components exposed to indoor uncontrolled air, dry air, or treated water.
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.

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, 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	Consistent with NUREG-2191. The Fire Protection AMP is used to manage loss of material, change in material properties, cracking, delamination, and separation for subliming compound fireproofing/fire barriers. This line item is used to evaluate structural items in Section 3.5.
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 AMP is used to manage loss of material, change in material properties, cracking, delamination, and separation for cementitious coating fireproofing/fire barriers. This line item is used to evaluate structural items in Section 3.5.
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 AMP is used to manage loss of material, change in material properties, cracking, delamination, and separation for subliming compound fireproofing/fire barriers. This line item is used to evaluate structural items in Section 3.5.

Table 3.3.2-1: Chemical and Volume 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	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	3.2-1, 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
Bolting	Mechanical closure	Stainless steel	Air – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.2-1, 015	A
Heat exchanger (Letdown channel head and cover)	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	A
Heat exchanger (Letdown channel head and cover)	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	A
Heat exchanger (Letdown channel head and cover) (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

Table 3.3.2-1: Chemical and Volume 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 (Letdown channel head and cover) (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 (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	A
Heat exchanger (Letdown 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	A
Heat exchanger (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	C
Heat exchanger (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	A
Heat exchanger (Letdown 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	A
Heat exchanger (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	C
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	A

Table 3.3.2-1: Chemical and Volume 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 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	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
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	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	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

Table 3.3.2-1: Chemical and Volume 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 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	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	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	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	A
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	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	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	A

Table 3.3.2-1: Chemical and Volume 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 >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	A
Housing (charging pump strainers, suction stabilizers, pulsation dampers, purification filters, letdown strainers, boric acid suction strainers and ion exchangers)	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
Housing (charging pump strainers, suction stabilizers, pulsation dampers, purification filters, letdown strainers, boric acid suction strainers and ion exchangers)	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
Housing (charging pump strainers, suction stabilizers, pulsation dampers, purification filters, letdown strainers, boric acid suction strainers and ion exchangers)	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	A

Table 3.3.2-1: Chemical and Volume 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**
Orifice	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
Orifice	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
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)	VII.E1.AP-79	3.3-1, 125	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)	VII.E1.AP-79	3.3-1, 125	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	A

Table 3.3.2-1: Chemical and Volume 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	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.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	Air – outdoor (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 – outdoor (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	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	A

Table 3.3.2-1: Chemical and Volume 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)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	A
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 4.3.2, 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 – 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.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	A

Table 3.3.2-1: Chemical and Volume 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 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	A
Pump casing (Boric Acid Makeup)	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 (Boric Acid Makeup)	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 (Boric Acid Makeup)	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	A
Pump casing (Charging)	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 (Charging)	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 (Charging)	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	A

Table 3.3.2-1: Chemical and Volume 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**
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	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	A
Tank (Boric Acid Makeup)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E1.AP-209c	3.3-1, 004	A

Table 3.3.2-1: Chemical and Volume 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 Makeup)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E1.AP-221c	3.3-1, 006	A
Tank (Boric Acid Makeup)	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	A
Tank (Boric Acid Makeup) (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
Tank (Boric Acid Makeup) (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
Tank (Volume Control)	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 (Volume Control)	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 (Volume Control)	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A

Table 3.3.2-1: Chemical and Volume 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 (Volume Control)	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	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
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.E1.AP-79	3.3-1, 125	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)	VII.E1.AP-82	3.3-1, 028	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.E1.AP-221b	3.3-1, 006	A

Table 3.3.2-1: Chemical and Volume 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	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	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	A
Valve body	Pressure boundary	CASS	Treated borated water >482°F (int)	Loss of fracture toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B.2.3.6)	V.D1.E-47	3.2-1, 010	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.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	A

Table 3.3.2-1: Chemical and Volume 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 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	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

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	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
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
Heat exchanger (CCW channels and doors)	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 (CCW channels and doors)	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	C
Heat exchanger (CCW channels and doors)	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 (CCW channels and doors)	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	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 (CCW channels and doors) (Unit 1 only)	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
Heat exchanger (CCW channels and doors) (Unit 2 only)	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 (CCW shell) (Unit 1 only)	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
Heat exchanger (CCW shell) (Unit 2 only)	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 (CCW shells and baffles)	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	A
Heat exchanger (CCW tubes)	Heat transfer	Copper alloy > 15% Zn	Raw water (int)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3-1, 042	A
Heat exchanger (CCW tubes)	Heat transfer	Copper alloy > 15% Zn	Treated water (ext)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-205	3.3-1, 050	A
Heat exchanger (CCW tubes)	Pressure boundary	Copper alloy > 15% Zn	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3-1, 072	A
Heat exchanger (CCW tubes)	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-179	3.3-1, 038	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 (CCW tubes)	Pressure boundary	Copper alloy > 15% Zn	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3-1, 046	C
Heat exchanger (CCW tubes)	Pressure boundary	Copper alloy > 15% Zn	Treated water (ext)	Loss of material	Selective Leaching (B.2.3.21)	VII.C2.AP-43	3.3-1, 072	C
Heat exchanger (CCW 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	A
Heat exchanger (CCW tubesheet)	Pressure boundary	Copper alloy > 8% Al	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3-1, 072	A
Heat exchanger (CCW tubesheet)	Pressure boundary	Copper alloy > 8% Al	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	A
Heat exchanger (CCW tubesheet)	Pressure boundary	Copper alloy > 8% Al	Treated water (ext)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3-1, 046	C
Heat exchanger (CCW tubesheet)	Pressure boundary	Copper alloy > 8% Al	Treated water (ext)	Loss of material	Selective Leaching (B.2.3.21)	VII.C2.AP-43	3.3-1, 072	C
Orifice	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
Orifice	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
Orifice	Pressure boundary	Stainless steel	Air – outdoor (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
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	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	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	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	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	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 water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	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	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.2.3.24)	V.A.E-29	3.2-1, 044	A
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	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	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	Air – outdoor (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	Pressure boundary	Stainless steel	Air – outdoor (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	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	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)	VII.I.A-405a	3.3-1, 132	A
Pump casing (component cooling water)	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 (component cooling water)	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	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
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	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Sight glass	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	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	Air – indoor uncontrolled (int)	None	None	VII.J.AP-48	3.3-1, 117	A
Sight glass	Pressure boundary	Glass	Treated water (int)	None	None	VII.J.AP-166	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.E1.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.E1.AP-221b	3.3-1, 006	A
Sight glass	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	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

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**
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	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	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 water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	A
Tank (component cooling water 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 (component cooling water surge)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Tank (component cooling water 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	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 (component cooling water surge)	Pressure boundary	Coating	Air – indoor uncontrolled (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.D.A-416	3.3-1, 138	A
Tank (component cooling water surge)	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.C2.A-416	3.3-1, 138	A
Thermowell	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
Thermowell	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	A
Thermowell	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C2.AP-43	3.3-1, 072	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 3.3.2-2: 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**
Thermowell	Pressure boundary	Stainless steel	Air – outdoor (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 – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.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	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	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	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.2.3.24)	V.A.E-29	3.2-1, 044	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	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	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	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	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	A
Valve body	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
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.C2.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.2.3.24)	VII.C2.AP-209c	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 (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C2.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.E1.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.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	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP 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 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 AMP is used to manage the wall thinning due to erosion aging effect.

Table 3.3.2-3: Demineralized Makeup 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)	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	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-87	3.4-1, 085	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

Table 3.3.2-3: Demineralized Makeup 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**
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
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 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	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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	Aluminum	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	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
Air motor	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
Air motor lubricator	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
Air motor lubricator	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
Air motor lubricator	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
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

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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 – 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
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
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	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	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	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

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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.2.3.24)	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.2.3.24)	VII.H2.AP-104	3.3-1, 088	A
Flame arrestor	Fire prevention	Aluminum	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.A-451b	3.3-1, 189	A
Flame arrestor	Fire prevention	Aluminum	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.A-763b	3.3-1, 234	A
Flame arrestor	Fire prevention	Aluminum	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-451c	3.3-1, 004	A
Flame arrestor	Fire prevention	Aluminum	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-763c	3.3-1, 234	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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	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
Flame arrestor	Fire prevention	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
Flame arrestor	Fire prevention	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H1.AP-209c	3.3-1, 004	A
Flame arrestor	Fire prevention	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H1.AP-221c	3.3-1, 006	A
Flexible hose	Pressure boundary	Polyester	Air – dry (int)	Hardening or loss of strength Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-797b	3.3-1, 263	A
Flexible hose	Pressure boundary	Polyester	Air – indoor uncontrolled (ext)	Hardening or loss of strength Loss of material Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-797a	3.3-1, 263	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flexible hose	Pressure boundary	Rubber	Air – dry (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.A-729	3.3-1, 085	C
Flexible hose	Pressure boundary	Rubber	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
Flexible hose	Pressure boundary	Rubber	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
Flexible hose	Pressure boundary	Rubber	Treated water (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C2.AP-259	3.3-1, 085	A
Flexible hose	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
Flexible hose	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
Flexible hose	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 3.3.2-4: Diesel Generators and Support Systems – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flexible hose	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
Flexible hose	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	A
Flexible hose	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	A
Heat exchanger (lube oil 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 (lube oil shell)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3-1, 098	A
Heat exchanger (lube oil tubes)	Heat transfer	Copper alloy > 15% Zn	Lubricating oil (ext)	Reduction of heat transfer	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.A-791	3.3-1, 257	C
Heat exchanger (lube oil 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	A
Heat exchanger (lube oil tubes)	Pressure boundary	Copper alloy > 15% Zn	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	C
Heat exchanger (lube oil 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	C

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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 (lube oil 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	C
Heat exchanger (lube oil 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 (lube oil tubesheet)	Pressure boundary	Copper alloy > 15% Zn	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	C
Heat exchanger (lube oil 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	C
Heat exchanger (lube oil tubesheet)	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	C
Heat exchanger (lube oil tubesheet)	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 (radiator headers)	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 (radiator headers)	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	C
Heat exchanger (radiator tubes)	Heat transfer	Copper alloy > 15% Zn	Air – indoor uncontrolled (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 (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	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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 (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 (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	C
Heat exchanger (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	C
Heat exchanger (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 (Unit 1 lube oil channel header)	Pressure boundary	Gray cast iron	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 (Unit 1 lube oil channel header)	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	C
Heat exchanger (Unit 1 lube oil channel header)	Pressure boundary	Gray cast iron	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.F4.AP-31	3.3-1, 072	C
Heat exchanger (Unit 1 radiator fins)	Heat transfer	Copper alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-426	3.4-1, 075	C, 1
Heat exchanger (Unit 1 radiator fins)	Heat transfer	Copper alloy	Air – indoor uncontrolled (ext)	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-424	3.2-1, 081	C

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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 (Unit 2 lube oil channel header)	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 (Unit 2 lube oil channel header)	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	C
Heat exchanger (Unit 2 radiator fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.A-451b	3.3-1, 189	C
Heat exchanger (Unit 2 radiator fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F4.A-771b	3.3-1, 242	A, 1
Heat exchanger (Unit 2 radiator fins)	Heat transfer	Aluminum	Air – indoor uncontrolled (ext)	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-424	3.2-1, 081	C
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

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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 (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H1.AP-209c	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H1.AP-221c	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.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	A
Orifice	Throttle	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H1.AP-209c	3.3-1, 004	A
Orifice	Throttle	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H1.AP-221c	3.3-1, 006	A
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 3.3.2-4: Diesel Generators and Support Systems – Summary 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.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	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.2.3.24)	V.A.E-29	3.2-1, 044	A
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.2.3.24)	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.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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.H2.AP-202	3.3-1, 045	A
Piping	Pressure boundary	Carbon steel	Underground (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-284	3.3-1, 109	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	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	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-199	3.3-1, 046	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	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.AP-209b	3.3-1, 004	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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.2.3.24)	VII.H1.AP-221c	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
Piping	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	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	A
Piping	Pressure boundary	Stainless steel	Underground (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-714b	3.3-1, 146	A
Piping	Pressure boundary	Stainless steel	Underground (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-775b	3.3-1, 246	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	Pressure boundary	Carbon steel	Diesel exhaust (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Non-Class 1 Components	VII.E1.A-34	3.3-1, 002	A
Piping and piping components	Pressure boundary	Stainless steel	Diesel exhaust (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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 – 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)	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.2.3.24)	V.A.E-29	3.2-1, 044	A
Piping and piping components	Structural integrity (attached)	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 and piping components	Structural integrity (attached)	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Piping and piping components	Structural integrity (attached)	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 and piping components	Structural integrity (attached)	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	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	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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.H1.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.H1.AP-221b	3.3-1, 006	A
Piping and piping components	Structural integrity (attached)	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
Piping and piping components	Structural integrity (attached)	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	A
Pump casing (cooling water)	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 (cooling water)	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	A
Pump casing (engine-driven fuel)	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: Diesel Generators and Support Systems – Summary 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 (engine-driven fuel)	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 (fuel oil transfer)	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
Pump casing (fuel oil transfer)	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
Pump casing (fuel oil transfer)	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-136a	3.3-1, 071	B A
Pump casing (lube 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
Pump casing (lube oil)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Pump casing (priming)	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 (priming)	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 3.3.2-4: Diesel Generators and Support Systems – Summary 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	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	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Sight glass	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	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	Air – indoor uncontrolled (int)	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
Sight glass	Pressure boundary	Plexiglas	Air – indoor uncontrolled (ext)	Hardening or loss of strength Loss of material Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-797a	3.3-1, 263	A
Sight glass	Pressure boundary	Plexiglas	Air – indoor uncontrolled (int)	Hardening or loss of strength Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-797b	3.3-1, 263	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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	Plexiglas	Treated water (int)	Hardening or loss of strength Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-797b	3.3-1, 263	A
Sight glass	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
Sight glass	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
Sight glass	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H1.AP-209c	3.3-1, 004	A
Sight glass	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H1.AP-221c	3.3-1, 006	A
Sight glass	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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	Diesel exhaust (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.AP-104	3.3-1, 088	A
Strainer	Filter	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Strainer	Filter	Copper alloy > 15% Zn	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	A
Strainer	Filter	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
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	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-162	3.3-1, 099	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	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	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	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	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.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Strainer	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
Strainer	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.AP-209b	3.3-1, 004	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.AP-221b	3.3-1, 006	A
Tank (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 (day)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Tank (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 (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 (expansion)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Tank (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	A
Tank (Unit 1 air start)	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 3.3.2-4: Diesel Generators and Support Systems – Summary 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 (Unit 1 air start)	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 (Unit 1 diesel 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	B
Tank (Unit 1 diesel oil storage)	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-401	3.3-1, 128	B
Tank (Unit 1 diesel 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	B
Tank (Unit 1 diesel 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 (Unit 1 diesel oil storage)	Pressure boundary	Coating	Air – outdoor (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.D.A-416	3.3-1, 138	A
Tank (Unit 2 air start)	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
Tank (Unit 2 air start)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.AP-209b	3.3-1, 004	C

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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 (Unit 2 air start)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.H2.AP-221b	3.3-1, 006	C
Tank (Unit 2 diesel oil storage)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Tank (Unit 2 diesel 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.A-105	3.3-1, 070	B A
Tank (Unit 2 diesel oil storage)	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 (Unit 2 diesel 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	A
Tank (Unit 2 diesel oil storage)	Pressure boundary	Coating	Air – indoor uncontrolled (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.D.A-416	3.3-1, 138	A
Tank (Unit 2 diesel 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	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Thermowell	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
Thermowell	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
Thermowell	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-136a	3.3-1, 071	B 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	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

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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.2.3.24)	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.2.3.25) 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	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	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.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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 (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	Treated water (int)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-473a	3.3-1, 160	C
Valve body	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-199	3.3-1, 046	A
Valve body	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
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
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H1.AP-209c	3.3-1, 004	A

Table 3.3.2-4: Diesel Generators and Support Systems – Summary 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.2.3.24)	VII.H1.AP-221c	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.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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.

Plant Specific Notes

1. Plant experience shows a history of loss of material and fouling due to corrosion on fins.

Table 3.3.2-5: Fire Protection / Service 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
Accumulator	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
Accumulator	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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	Carbon steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	C
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	A
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	Cast iron	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	Cast iron	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	Cast iron	Air – outdoor (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting	Mechanical closure	Cast iron	Air – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A

Table 3.3.2-5: Fire Protection / Service 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	Cast iron	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	C
Bolting	Mechanical closure	Cast iron	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-241	3.3-1, 109	A
Bolting	Mechanical closure	Cast iron	Soil (ext)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-02	3.3-1, 072	C
Bolting	Mechanical closure	Cast iron	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
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	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	C
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	A
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
Drip pan	Direct flow	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

Table 3.3.2-5: Fire Protection / Service 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
Drip pan	Direct flow	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
Drip pan	Direct flow	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-209c	3.3-1, 004	A
Drip pan	Direct flow	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-221c	3.3-1, 006	A
Drip pan	Direct flow	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.G.AP-138	3.3-1, 100	C
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	Air – outdoor (int)	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	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	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
Fire hydrant	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	A

Table 3.3.2-5: Fire Protection / Service 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**
Fire hydrant	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	A
Fire hydrant	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
Flame arrestor	Fire prevention	Aluminum	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.A-451b	3.3-1, 189	A
Flame arrestor	Fire prevention	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
Flame arrestor	Fire prevention	Aluminum	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-451c	3.3-1, 189	A
Flame arrestor	Fire prevention	Aluminum	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-763c	3.3-1, 234	A
Flame arrestor	Fire prevention	Aluminum	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.G.AP-162	3.3-1, 099	A
Flame arrestor	Fire prevention	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

Table 3.3.2-5: Fire Protection / Service 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**
Flame arrestor	Fire prevention	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
Flame arrestor	Fire prevention	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-209c	3.3-1, 004	A
Flame arrestor	Fire prevention	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-221c	3.3-1, 006	A
Flame arrestor	Fire prevention	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.G.AP-138	3.3-1, 100	A
Flexible hose	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
Flexible hose	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 3.3.2-5: Fire Protection / Service 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**
Flexible hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-209c	3.3-1, 004	A
Flexible hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-221c	3.3-1, 006	A
Flexible hose	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.G.AP-138	3.3-1, 100	A
Flexible hose (Unit 1 only)	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
Flexible hose (Unit 1 only)	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
Flexible hose (Unit 1 only)	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A
Hose reel	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Hose reel	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Hose reel	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Hose reel	Pressure boundary	Copper alloy	Air – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-5: Fire Protection / Service 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
Hose reel	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
Hose reel	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
Hose reel	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
Hose reel	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Hose reel	Pressure boundary	Copper alloy > 15% Zn	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Hose reel	Pressure boundary	Copper alloy > 15% Zn	Air – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	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	Air – outdoor (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 3.3.2-5: Fire Protection / Service 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**
Nozzle	Pressure boundary	Copper alloy > 15% Zn	Air – outdoor (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 – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle	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, 3
Nozzle	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
Nozzle	Pressure boundary	Copper alloy > 15% Zn	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 > 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
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 (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
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
Nozzle	Spray	Copper alloy > 15% Zn	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Nozzle	Spray	Copper alloy > 15% Zn	Air – outdoor (int)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-404	3.3-1, 131	A
Nozzle	Spray	Copper alloy > 15% Zn	Raw water (int)	Cracking	Fire Water System (B.2.3.16)	VII.C1.A-473b	3.3-1, 160	E, 3

Table 3.3.2-5: Fire Protection / Service 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**
Nozzle	Spray	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
Nozzle	Spray	Copper alloy > 15% Zn	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 > 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
Nozzle (halon)(Unit 1 only)	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	A
Nozzle (halon)(Unit 1 only)	Pressure boundary	Galvanized steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Nozzle (halon)(Unit 1 only)	Spray	Galvanized steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Orifice	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
Orifice	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
Orifice	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
Orifice	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
Orifice	Throttle	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
Orifice	Throttle	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
Piping	Leakage boundary (spatial)	Galvanized 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

Table 3.3.2-5: Fire Protection / Service 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)	Galvanized steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3-1, 134	A
Piping	Leakage boundary (spatial)	Galvanized steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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.G.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.G.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.2.3.24)	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.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2

Table 3.3.2-5: Fire Protection / Service 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	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.2.3.24)	V.A.E-29	3.2-1, 044	A
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	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	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	A
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	A
Piping	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.G.AP-127	3.3-1, 097	A
Piping	Pressure boundary	Carbon steel	Raw water (ext)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	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

Table 3.3.2-5: Fire Protection / Service 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	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)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3-1, 134	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	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2
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	A
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	A
Piping	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.G.A-416	3.3-1, 138	A
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	A
Piping	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-5: Fire Protection / Service 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	Copper alloy	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping	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
Piping	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
Piping	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
Piping	Pressure boundary	Copper alloy > 15% Zn	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping	Pressure boundary	Copper alloy > 15% Zn	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Piping	Pressure boundary	Copper alloy > 15% Zn	Air – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping	Pressure boundary	Ductile 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	Ductile iron	Concrete (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	A
Piping	Pressure boundary	Ductile 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	Ductile 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	Ductile 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	Ductile iron	Raw water (int)	Wall thinning – erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-5: Fire Protection / Service 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	Ductile iron	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	A
Piping	Pressure boundary	Ductile iron	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	A
Piping	Pressure boundary	Ductile iron	Soil (ext)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-02	3.3-1, 072	A
Piping	Pressure boundary	Galvanized 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	Galvanized steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Piping	Pressure boundary	Galvanized 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	Galvanized 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	Galvanized 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	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
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

Table 3.3.2-5: Fire Protection / Service 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	Gray cast iron	Concrete (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	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	A
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	A
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	PVC/CPVC	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-268	3.3-1, 119	A
Piping	Pressure boundary	PVC/CPVC	Air – indoor uncontrolled (int)	None	None	VII.J.AP-268	3.3-1, 119	A
Piping	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
Piping	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 3.3.2-5: Fire Protection / Service 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 (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.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.2.3.24)	VII.G.AP-221c	3.3-1, 006	A
Piping	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
Piping	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
Piping	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-209c	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-221c	3.3-1, 006	A

Table 3.3.2-5: Fire Protection / Service 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	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3-1, 134	A
Piping	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2
Piping (halon) (Unit 1 only)	Pressure boundary	Galvanized steel	Air – outdoor (ext)	Loss of material	Fire Protection (B.2.3.15)	VII.G.AP-150	3.3-1, 058	A
Piping (halon) (Unit 1 only)	Pressure boundary	Galvanized steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Piping (Unit 1 only)	Leakage boundary (spatial)	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	A
Piping (Unit 1 only)	Pressure boundary	Copper alloy > 15% Zn	Gas (int)	None	None	VII.J.AP-9	3.3-1, 114	A
Piping (Unit 1 only)	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	A
Piping (Unit 1 only)	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	None	None	VII.J.AP-13	3.3-1, 116	A
Pump casing (domestic water pump)	Pressure boundary	Ductile 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
Pump casing (domestic water pump)	Pressure boundary	Ductile 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 (domestic water pump)	Pressure boundary	Ductile iron	Raw water (int)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	A

Table 3.3.2-5: Fire Protection / Service 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
Pump casing (domestic water pump)	Pressure boundary	Ductile iron	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	A
Pump casing (fire water pump)	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
Pump casing (fire water pump)	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 (fire water pump)	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 (fire water pump)	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
Pump casing (yard sump pump 2A)	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
Pump casing (yard sump pump 2A)	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
Pump casing (yard sump pump 2A)	Pressure boundary	Stainless steel	Raw water (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E5.A-411	3.3-1, 135	G, 5
Pump casing (yard sump pump 2A)	Pressure boundary	Stainless steel	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.G.S-436	3.4-1, 089	A

Table 3.3.2-5: Fire Protection / Service 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**
Pump casing (yard sump pump 2A)	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2
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	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
RCP oil collection	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.G.AP-127	3.3-1, 097	C
RCP oil collection	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	C
RCP oil collection	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	C

Table 3.3.2-5: Fire Protection / Service 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**
RCP oil collection	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-209c	3.3-1, 004	C
RCP oil collection	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-221c	3.3-1, 006	C
RCP oil collection	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.G.AP-138	3.3-1, 100	C
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	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Sight glass	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

Table 3.3.2-5: Fire Protection / Service 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
Sight glass	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Sight glass	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.G.AP-127	3.3-1, 097	A
Sight glass	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
Sight glass	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
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	Air – indoor uncontrolled (int)	None	None	VII.J.AP-48	3.3-1, 117	A
Sight glass	Pressure boundary	Glass	Air – outdoor (ext)	None	None	VII.J.AP-48	3.3-1, 117	A
Sight glass	Pressure boundary	Glass	Air – outdoor (int)	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
Sight glass	Pressure boundary	Glass	Raw water (int)	None	None	VII.J.AP-50	3.3-1, 117	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	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
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

Table 3.3.2-5: Fire Protection / Service 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**
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
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	Filter	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
Strainer	Filter	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
Strainer	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Strainer	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Strainer	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
Strainer	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
Strainer	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
Strainer	Pressure boundary	Copper alloy > 15% Zn	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Strainer	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, 3
Strainer	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
Strainer	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
Strainer	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

Table 3.3.2-5: Fire Protection / Service 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**
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	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
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 (City Water Storage Tanks)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3-1, 136	A
Tank (City Water Storage Tanks)	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3-1, 136	A
Tank (City Water Storage Tanks)	Pressure boundary	Carbon steel	Concrete (ext)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3-1, 136	A
Tank (City Water Storage Tanks)	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 (City Water Storage Tanks)	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
Tank (City Water Storage Tanks)	Pressure boundary	Coating	Air – outdoor (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.D.A-416	3.3-1, 138	A

Table 3.3.2-5: Fire Protection / Service 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 (City Water Storage Tanks)	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.G.A-416	3.3-1, 138	C
Tank (Hydropneumatic Tank)	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
Tank (Hydropneumatic Tank)	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Tank (Hydropneumatic Tank)	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 (Hydropneumatic Tank)	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
Tank (Nu-Matic Water Control for Hydropneumatic Tank)	Pressure boundary	Fiberglass	Air – outdoor (ext)	Cracking Blistering Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-720	3.3-1, 150	A
Tank (Nu-Matic Water Control for Hydropneumatic Tank)	Pressure boundary	Fiberglass	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-495	3.3-1, 159	A

Table 3.3.2-5: Fire Protection / Service 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 (Nu-Matic Water Control for Hydropneumatic Tank)	Pressure boundary	Fiberglass	Raw water (int)	Cracking Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-644	3.3-1, 175	A
Tank (Nu-Matic Water Control for Hydropneumatic Tank)	Pressure boundary	Fiberglass	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-645	3.3-1, 176	A
Tank (Unit 1 cable spreading room halon tank)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Fire Protection (B.2.3.15)	VII.G.AP-150	3.3-1, 058	A
Tank (Unit 1 cable spreading room halon tank)	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Tank (Unit 1 halon nitrogen tank)	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
Tank (Unit 1 halon nitrogen tank)	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	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.2.3.24)	VII.C1.A-727	3.3-1, 134	A
Valve body	Leakage boundary (spatial)	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2

Table 3.3.2-5: Fire Protection / Service 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.2.3.24)	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	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Valve body	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.G.AP-127	3.3-1, 097	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	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-5: Fire Protection / Service 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	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	Air – outdoor (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	Fire Water System (B.2.3.16)	VII.C1.A-473b	3.3-1, 160	E, 3
Valve body	Pressure boundary	Copper alloy > 15% Zn	Raw water (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-473b	3.3-1, 160	E, 4
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)	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	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2

Table 3.3.2-5: Fire Protection / Service 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	Ductile 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	Ductile 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	Ductile 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	Ductile 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	Ductile 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	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	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	A

Table 3.3.2-5: Fire Protection / Service 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	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	A
Valve body	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
Valve body	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
Valve body	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
Valve body	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-209c	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-221c	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	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, 2
Valve body (halon) (Unit 1 only)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Fire Protection (B.2.3.15)	VII.G.AP-150	3.3-1, 058	A

Table 3.3.2-5: Fire Protection / Service 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 (halon) (Unit 1 only)	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Valve body (Unit 2 only)	Leakage boundary (spatial)	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 (Unit 2 only)	Leakage boundary (spatial)	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 (Unit 2 only)	Pressure boundary	Copper alloy	Air – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body (Unit 2 only)	Pressure boundary	Copper alloy > 15% Zn	Air – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body (Unit 2 only)	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 (Unit 2 only)	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
Vortex breaker	Vortex prevention	Carbon steel	Raw water (ext)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3-1, 193	A
Vortex breaker	Vortex prevention	Carbon steel	Raw water (ext)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3-1, 136	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP 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 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.
G. Environment not in NUREG-2191 for this component and material.

Plant Specific Notes

1. The Fire Water System AMP is used to manage the wall thinning due to erosion aging effect for fire protection components exposed to raw water.
2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage the wall thinning due to erosion aging effect for service water components exposed to raw water.
3. The Fire Water System AMP is used to manage the cracking aging effect for copper alloy >15% Zn components internally exposed to raw water.
4. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage the cracking aging effect for copper alloy >15% Zn components internally exposed to raw water.
5. The External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material for the external surfaces of the yard sump pump 2A.

Table 3.3.2-6: Fuel Pool 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
Heat exchanger (spent fuel pool channel cover (facing))	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	C
Heat exchanger (spent fuel pool channel cover)	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 (spent fuel pool channel cylinders and flanges)	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	C
Heat exchanger (spent fuel pool channel cylinders and flanges)	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	C
Heat exchanger (spent fuel pool channel cylinders and flanges)	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	C

Table 3.3.2-6: Fuel Pool 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) (Unit 2 only)	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 (spent fuel pool shell) (Unit 2 only)	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	A
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	C
Heat exchanger (spent fuel pool 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	A
Heat exchanger (spent fuel pool tubes) (Unit 2 only)	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	A
Heat exchanger (spent fuel pool tubes) (Unit 2 only)	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	A
Heat exchanger (spent fuel pool tubesheets)	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	C
Heat exchanger (spent fuel pool tubesheets)	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	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.C2.AP-221b	3.3-1, 006	A

Table 3.3.2-6: Fuel Pool 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	A
Pump casing (spent fuel pool)	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 (spent fuel pool)	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 (spent fuel pool)	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	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	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.C2.AP-221b	3.3-1, 006	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	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 3.3.2-6: Fuel Pool 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.C2.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	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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
Accumulator	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
Accumulator	Pressure boundary	Galvanized 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	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	A
Accumulator (Unit 1 only)	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	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 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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
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
Filter	Filter	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Filter	Filter	Stainless 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	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.AP-209c	3.3-1, 004	A
Filter	Filter	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.AP-221c	3.3-1, 006	A

Table 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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.2.3.24)	V.A.E-29	3.2-1, 044	A
Filter	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
Filter	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
Filter	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
Filter	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.AP-209c	3.3-1, 004	A
Filter	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.AP-221c	3.3-1, 006	A

Table 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-209b	3.3-1, 004	A
Filter	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-221b	3.3-1, 006	A
Flexible hose	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
Flexible hose	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
Flexible hose	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-504	3.3-1, 085	A
Flexible hose	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.AP-103	3.3-1, 096	A
Flexible hose	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 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Flexible hose	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
Flexible hose	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
Flexible hose	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-209b	3.3-1, 004	A
Flexible hose	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-221b	3.3-1, 006	A
Instrument Air Dryer 1A (Unit 1 only)	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
Instrument Air Dryer 1A (Unit 1 only)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Instrument Air Dryer 1B (Unit 1 only)	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 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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 Air Dryer 1B (Unit 1 only)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Instrument Air Receiver (Unit 1 only)	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
Instrument Air Receiver (Unit 1 only)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Orifice	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
Orifice	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
Orifice	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
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-209b	3.3-1, 004	A

Table 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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 – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-221b	3.3-1, 006	A
Orifice	Throttle	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	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.2.3.24)	V.A.E-29	3.2-1, 044	A
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	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 – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping	Pressure boundary	Galvanized steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	A
Piping	Pressure boundary	Galvanized 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	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	Air – outdoor (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 – outdoor (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)	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 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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)	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
Rupture disc	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
Rupture disc	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-209b	3.3-1, 004	A
Rupture disc	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.AP-221b	3.3-1, 006	A
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	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-48	3.3-1, 117	A
Sight glass	Pressure boundary	Glass	Air – indoor uncontrolled (int)	None	None	VII.J.AP-48	3.3-1, 117	A
Silencer (Unit 1 only)	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 (Unit 1 only)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	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
Thermowell	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
Thermowell	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
Thermowell	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
Thermowell	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

Table 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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 (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.AP-209c	3.3-1, 004	A
Thermowell	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.AP-221c	3.3-1, 006	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 – 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)	VII.D.A-451b	3.3-1, 189	A
Valve body	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E5.A-763b	3.3-1, 234	A
Valve body	Pressure boundary	Aluminum	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.D.A-451b	3.3-1, 189	A

Table 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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	Aluminum	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E5.A-763b	3.3-1, 234	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 – 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	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	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	Air – outdoor (ext)	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

Table 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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 (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	Air – outdoor (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 – 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.2.3.24)	VII.D.AP-209c	3.3-1, 004	A

Table 3.3.2-7: Instrument Air / Miscellaneous Bulk Gas Supply – Summary 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.2.3.24)	VII.D.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.D.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.D.AP-221b	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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	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	A
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	Copper alloy > 8% Al	Raw water (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-423	3.3-1, 142	A
Bolting	Mechanical closure	Copper alloy > 8% Al	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	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 (Unit 1 only)	Mechanical closure	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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 (Unit 1 only)	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 (Unit 1 only)	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 (Unit 1 only)	Mechanical closure	Stainless steel	Raw water (ext)	Cracking	Bolting Integrity (B.2.3.9)	VII.I.A-426	3.3-1, 145	A
Bolting (Unit 1 only)	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 (Unit 1 only)	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 (Unit 2 only)	Mechanical closure	Monel	Air – indoor uncontrolled (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-03	3.3-1, 012	A
Bolting (Unit 2 only)	Mechanical closure	Monel	Air – indoor uncontrolled (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Bolting (Unit 2 only)	Mechanical closure	Monel	Raw water (ext)	Loss of material	Bolting Integrity (B.2.3.9)	VII.I.A-423	3.3-1, 142	A
Bolting (Unit 2 only)	Mechanical closure	Monel	Raw water (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VII.I.AP-124	3.3-1, 015	A
Expansion joint (Unit 1 only)	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 (Unit 1 only)	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 (Unit 1 only)	Pressure boundary	Elastomer	Raw water (int)	Hardening or loss of strength Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.AP-75	3.3-1, 085	A

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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 (Unit 1 only)	Pressure boundary	Elastomer	Raw water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.AP-76	3.3-1, 096	A
Expansion joint (Unit 2 only)	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 (Unit 2 only)	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 (Unit 2 only)	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	A
Expansion joint (Unit 2 only)	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	Pressure boundary	Monel	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	Monel	Air – outdoor (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	Monel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-206	3.3-1, 034	A

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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	Monel	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	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – outdoor (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	A
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	Monel	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	Throttle	Monel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Orifice	Throttle	Monel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-206	3.3-1, 034	A
Orifice	Throttle	Monel	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 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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	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	A
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
Orifice (Unit 2 only)	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
Orifice (Unit 2 only)	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	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 – 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	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	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	A

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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	Concrete (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	A
Piping	Pressure boundary	Carbon steel	Raw water (ext)	Long-term loss of material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3-1, 193	A
Piping	Pressure boundary	Carbon steel	Raw water (ext)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-400a	3.3-1, 127	A
Piping	Pressure boundary	Carbon steel	Raw water (ext)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3-1, 037	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
Piping	Pressure boundary	Carbon steel	Raw water (int)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-400a	3.3-1, 127	A
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	A
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	A
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	A
Piping	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	A

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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	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	A
Piping	Pressure boundary	Copper alloy	Air – outdoor (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping	Pressure boundary	Copper alloy	Air – outdoor (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping	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
Piping	Pressure boundary	Copper alloy > 15% Zn	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Piping	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	A
Piping	Pressure boundary	Copper alloy > 15% Zn	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3-1, 072	A
Piping	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	A
Piping	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
Piping	Pressure boundary	Copper alloy > 8% Al	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: Intake Cooling Water / Emergency Cooling Canal – Summary 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 > 8% Al	Raw water (ext)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3-1, 160	A
Piping	Pressure boundary	Copper alloy > 8% Al	Raw water (ext)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3-1, 034	A
Piping	Pressure boundary	Copper alloy > 8% Al	Raw water (ext)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3-1, 072	A
Piping	Pressure boundary	Copper alloy > 8% Al	Raw water (int)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3-1, 160	A
Piping	Pressure boundary	Copper alloy > 8% Al	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3-1, 072	A
Piping	Pressure boundary	Copper alloy > 8% Al	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	A
Piping	Pressure boundary	Copper alloy > 8% Al	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	Monel	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	Monel	Air – outdoor (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	Monel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-206	3.3-1, 034	A
Piping	Pressure boundary	Monel	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 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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.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	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.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.2.3.24)	VII.C1.AP-221c	3.3-1, 006	A
Piping	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
Piping	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

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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 – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.AP-209c	3.3-1, 004	A
Piping	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.AP-221c	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3-1, 134	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	A
Piping	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2
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 (Unit 1 only)	Pressure boundary	Stainless steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	A
Piping (Unit 1 only)	Pressure boundary	Stainless steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-137	3.3-1, 107	A

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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 (Unit 2 only)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Piping (Unit 2 only)	Pressure boundary	Fiberglass	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-719	3.3-1, 082	A
Piping (Unit 2 only)	Pressure boundary	Fiberglass	Raw water (int)	Cracking Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-238	3.3-1, 030a	A
Piping and piping components	Structural integrity (attached)	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 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
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.2.3.24)	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.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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)	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.2.3.24)	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.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2
Pump casing (Intake cooling water)	Pressure boundary	Copper alloy > 8% Al	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Pump casing (Intake cooling water)	Pressure boundary	Copper alloy > 8% Al	Raw water (ext)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3-1, 160	A
Pump casing (Intake cooling water)	Pressure boundary	Copper alloy > 8% Al	Raw water (ext)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3-1, 034	A
Pump casing (Intake cooling water)	Pressure boundary	Copper alloy > 8% Al	Raw water (ext)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3-1, 072	A

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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 (Intake cooling water)	Pressure boundary	Copper alloy > 8% Al	Raw water (int)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3-1, 160	A
Pump casing (Intake cooling water)	Pressure boundary	Copper alloy > 8% Al	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3-1, 072	A
Pump casing (Intake cooling water)	Pressure boundary	Copper alloy > 8% Al	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	A
Pump casing (Intake cooling water)	Pressure boundary	Copper alloy > 8% Al	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
Pump casing (Intake cooling water)	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 (Intake cooling water)	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 (Intake cooling water)	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	A
Pump casing (Intake cooling water)	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	A
Pump casing (Intake cooling water)	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
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	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	A

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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	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	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	A
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
Strainer (Unit 1 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-209b	3.3-1, 004	A
Strainer (Unit 1 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221b	3.3-1, 006	A
Strainer (Unit 2 only)	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 (Unit 2 only)	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	Monel	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 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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	Monel	Air – outdoor (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	Monel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-206	3.3-1, 034	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 – 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	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	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-400a	3.3-1, 127	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	A
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	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	A

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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	Air – outdoor (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	A
Valve body	Pressure boundary	Copper alloy > 8% Al	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 > 8% Al	Raw water (ext)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3-1, 160	A
Valve body	Pressure boundary	Copper alloy > 8% Al	Raw water (ext)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3-1, 034	A
Valve body	Pressure boundary	Copper alloy > 8% Al	Raw water (ext)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3-1, 072	A
Valve body	Pressure boundary	Copper alloy > 8% Al	Raw water (int)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3-1, 160	A
Valve body	Pressure boundary	Copper alloy > 8% Al	Raw water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3-1, 072	A
Valve body	Pressure boundary	Copper alloy > 8% Al	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	A
Valve body	Pressure boundary	Copper alloy > 8% Al	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 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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	Monel	Air – outdoor (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	Monel	Raw water (int)	Loss of material Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-206	3.3-1, 034	A
Valve body	Pressure boundary	Monel	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	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

Table 3.3.2-8: Intake Cooling Water / Emergency Cooling Canal – Summary 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	Raw water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3-1, 134	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	A
Valve body	Pressure boundary	Stainless steel	Raw water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2
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
Valve body (Unit 1 only)	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 (Unit 1 only)	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 (Unit 1 only)	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
Valve body (Unit 1 only)	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	A
Valve body (Unit 1 only)	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

General Notes

A. Consistent with component, 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 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 AMP is used to manage wall thinning due to erosion for the interior surfaces of components within the intake cooling water system exposed to raw water not within the scope of the GL 89-13 program.

Table 3.3.2-9: Primary Makeup 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	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	A
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
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	A
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

Table 3.3.2-9: Primary Makeup 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
Expansion joint (Unit 2 only)	Pressure boundary	Elastomer	Air – outdoor (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 (Unit 2 only)	Pressure boundary	Elastomer	Air – outdoor (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 (Unit 2 only)	Pressure boundary	Elastomer	Treated water (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-75	3.3-1, 085	A
Expansion joint (Unit 2 only)	Pressure boundary	Elastomer	Treated water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-76	3.3-1, 096	A
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 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	A

Table 3.3.2-9: Primary Makeup 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**
Hose reel (Unit 2 only)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Hose reel (Unit 2 only)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle (Unit 2 only)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle (Unit 2 only)	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle (Unit 2 only)	Spray	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Nozzle (Unit 2 only)	Spray	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-221b	3.3-1, 006	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.B1.SP-87	3.4-1, 085	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.B1.SP-87	3.4-1, 085	A
Piping	Pressure boundary	Nickel alloy	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 3.3.2-9: Primary Makeup 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	Nickel alloy	Treated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-87	3.4-1, 085	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	Air – outdoor (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 – outdoor (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	Concrete (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	A
Piping	Pressure boundary	Stainless steel	Concrete (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-137	3.3-1, 107	A
Piping	Pressure boundary	Stainless steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	A
Piping	Pressure boundary	Stainless steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-137	3.3-1, 107	A

Table 3.3.2-9: Primary Makeup 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	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	A
Piping (Unit 1 only)	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 (Unit 1 only)	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 (Unit 1 only)	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	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 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	A

Table 3.3.2-9: Primary Makeup 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
Pump casing (primary water storage) (Unit 2 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Pump casing (primary water storage) (Unit 2 only)	Pressure boundary	Stainless steel	Air – outdoor (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 (primary water storage) (Unit 2 only)	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	A
Pump casing (treated water transfer)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E1.AP-209b	3.3-1, 004	A
Pump casing (treated water transfer)	Pressure boundary	Stainless steel	Air – outdoor (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 (treated water transfer)	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	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
Steel components (Unit 1 only)	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

Table 3.3.2-9: Primary Makeup 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**
Strainer	Filter	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	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 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	A
Tank (primary water storage) (Unit 2 only)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.C3.A-401	3.3-1, 128	B
Tank (primary water storage) (Unit 2 only)	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.C3.A-401	3.3-1, 128	B
Tank (primary water storage) (Unit 2 only)	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	B
Tank (primary water storage) (Unit 2 only)	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	B

Table 3.3.2-9: Primary Makeup 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 (primary water storage) (Unit 2 only)	Pressure boundary	Coating	Air – outdoor (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.D.A-416	3.3-1, 138	A
Tank (primary water storage) (Unit 2 only)	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	A
Tank (treated water storage)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.C3.A-401	3.3-1, 128	B
Tank (treated water storage)	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.C3.A-401	3.3-1, 128	B
Tank (treated water storage)	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	B
Tank (treated water storage)	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	B
Tank (treated water storage)	Pressure boundary	Coating	Air – outdoor (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.D.A-416	3.3-1, 138	A

Table 3.3.2-9: Primary Makeup 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 (treated water storage)	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	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	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	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	Air – outdoor (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 – outdoor (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 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	A

Table 3.3.2-9: Primary Makeup 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 (Unit 1 only)	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 (Unit 1 only)	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 (Unit 1 only)	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	A
Vortex breaker	Vortex prevention	Stainless steel	Treated water (ext)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-87	3.4-1, 085	A
Vortex breaker	Vortex prevention	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	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.3.2-10: 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
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	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	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 3.3.2-10: 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	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E1.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.2.3.24)	VII.E1.AP-221c	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	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.A-103	3.3-1, 124	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 (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
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

Table 3.3.2-10: 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	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	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E1.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.2.3.24)	VII.E1.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.E1.AP-79	3.3-1, 125	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.A-103	3.3-1, 124	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

Table 3.3.2-10: 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
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
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-209c	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-221c	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	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-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.E1.AP-221c	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	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.A-103	3.3-1, 124	A

Table 3.3.2-10: 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**
Valve body (insulated) (Unit 2 only)	Pressure boundary	CASS	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-734c	3.3-1, 205	A
Valve body (insulated) (Unit 2 only)	Pressure boundary	CASS	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
Valve body (Unit 2 only)	Pressure boundary	CASS	Treated borated water (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-79	3.3-1, 125	A
Valve body (Unit 2 only)	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	A
Valve body (Unit 2 only)	Pressure boundary	CASS	Treated borated water >482°F (int)	Loss of fracture toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B.2.3.6)	V.D1.E-47	3.2-1, 010	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.3.2-11: Turbine 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
Heat Exchanger (instrument air fan cooler fins)	Heat transfer	Copper alloy > 15% Zn	Air – indoor uncontrolled (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 (instrument air fan cooler fins)	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	C
Heat Exchanger (instrument air fan cooler 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 (instrument air fan cooler 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	A
Heat Exchanger (instrument air fan cooler tubes)	Heat transfer	Copper alloy > 15% Zn	Air – indoor uncontrolled (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 (instrument air fan cooler 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	A

Table 3.3.2-11: Turbine 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 (instrument air fan cooler tubes)	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	C
Heat Exchanger (instrument air fan cooler 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	A
Heat Exchanger (instrument air fan cooler tubes)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.E1.AP-203	3.3-1, 046	A
Heat Exchanger (instrument air fan cooler tubes)	Pressure boundary	Copper alloy > 15% Zn	Treated water (int)	Loss of material	Selective Leaching (B.2.3.21)	VII.C2.AP-43	3.3-1, 072	C
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	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	A
Pump casing (instrument air compressor cooling water recirculation)	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 (instrument air compressor cooling water recirculation)	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	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

Table 3.3.2-11: Turbine 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**
Sight glass	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	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	Treated water (int)	None	None	VII.J.AP-51	3.3-1, 117	A
Tank (instrument air compressor cooling water 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
Tank (instrument air compressor cooling water head)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2-1, 044	A
Tank (instrument air compressor cooling water head)	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	A
Tank (instrument air compressor cooling water head)	Pressure boundary	Coating	Air – indoor uncontrolled (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.D.A-416	3.3-1, 138	A
Tank (instrument air compressor cooling water head)	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.C2.A-416	3.3-1, 138	A

Table 3.3.2-11: Turbine 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
Thermowell	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
Thermowell	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
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	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	Treated water (int)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3-1, 045	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.3.2-12: 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
Demister	Moisture removal	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.AP-209c	3.3-1, 004	A
Demister	Moisture removal	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.AP-221c	3.3-1, 006	A
Duct	Pressure boundary	Ductile iron	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-778	3.3-1, 249	C
Duct	Pressure boundary	Ductile iron	Underground (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-284	3.3-1, 109	C
Duct	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	C

Table 3.3.2-12: 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	Galvanized steel	Air – indoor uncontrolled (int)	None	None	VII.J.AP-13	3.3-1, 116	C
Duct	Pressure boundary	Galvanized steel	Concrete (ext)	None	None	VII.J.AP-282	3.3-1, 112	C
Fan housing	Pressure boundary	Aluminum	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-451b	3.3-1, 189	A
Fan housing	Pressure boundary	Aluminum	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-763b	3.3-1, 234	A
Fan housing	Pressure boundary	Aluminum	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-451c	3.3-1, 189	A
Fan housing	Pressure boundary	Aluminum	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-763c	3.3-1, 234	A
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.2.3.24)	VII.F3.A-778	3.3-1, 249	C
Fan housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	C
Fan housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	None	None	VII.J.AP-13	3.3-1, 116	C

Table 3.3.2-12: 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**
Flex connection	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
Flex connection	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
Flex connection	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.A-504	3.3-1, 085	C
Flex connection	Pressure boundary	Elastomer	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.AP-103	3.3-1, 096	C
Housing	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-451b	3.3-1, 189	A
Housing	Pressure boundary	Aluminum	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-763b	3.3-1, 234	A
Housing	Pressure boundary	Aluminum	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-451c	3.3-1, 189	A
Housing	Pressure boundary	Aluminum	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-763c	3.3-1, 234	A

Table 3.3.2-12: 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**
Housing	Pressure boundary	Aluminum	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-451b	3.3-1, 189	A
Housing	Pressure boundary	Aluminum	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.A-763b	3.3-1, 234	A
Housing	Pressure boundary	Aluminum	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-451c	3.3-1, 189	A
Housing	Pressure boundary	Aluminum	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-763c	3.3-1, 234	A
Housing	Pressure boundary	Carbon steel	Air – indoor controlled (int)	None	None	VII.J.AP-2	3.3-1, 121	A
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
Housing	Pressure boundary	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-778	3.3-1, 249	C
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
Housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	C

Table 3.3.2-12: 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
Housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	None	None	VII.J.AP-13	3.3-1, 116	C
Housing	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
Housing	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
Housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.AP-209c	3.3-1, 004	A
Housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.AP-221c	3.3-1, 006	A
Housing supports	Structural support	Carbon steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-778	3.3-1, 249	C
Housing supports	Structural support	Galvanized steel	Air – indoor uncontrolled (int)	None	None	VII.J.AP-13	3.3-1, 116	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

Table 3.3.2-12: 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
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
HVAC closure bolting	Mechanical closure	Stainless steel	Air – outdoor (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
Orifice	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	C
Orifice	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (int)	None	None	VII.J.AP-13	3.3-1, 116	C
Orifice	Throttle	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	C
Orifice	Throttle	Galvanized steel	Air – indoor uncontrolled (int)	None	None	VII.J.AP-13	3.3-1, 116	C
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.2.3.24)	VII.F3.A-778	3.3-1, 249	C
Piping	Pressure boundary	Carbon steel	Concrete (ext)	None	None	VII.J.AP-282	3.3-1, 112	A
Piping	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-13	3.3-1, 116	C
Piping	Pressure boundary	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-13	3.3-1, 116	C

Table 3.3.2-12: 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	Stainless steel	Air – indoor controlled (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 controlled (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 (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.2.3.24)	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.2.3.24)	VII.F1.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.2.3.24)	VII.F3.A-778	3.3-1, 249	C

Table 3.3.2-12: 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)	Galvanized steel	Air – indoor uncontrolled (ext)	None	None	V.F.EP-14	3.2-1, 059	A
Piping and piping components	Structural integrity (attached)	Galvanized steel	Air – indoor uncontrolled (int)	None	None	V.F.EP-14	3.2-1, 059	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.2.3.24)	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.2.3.24)	VII.F1.AP-221c	3.3-1, 006	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
Thermowell	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
Thermowell	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

Table 3.3.2-12: 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	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.AP-209c	3.3-1, 004	A
Thermowell	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.AP-221c	3.3-1, 006	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.2.3.24)	VII.F3.A-778	3.3-1, 249	C
Valve body	Pressure boundary	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	Cast iron	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-778	3.3-1, 249	C
Valve body	Pressure boundary	Stainless steel	Air – indoor controlled (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 controlled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F3.AP-221b	3.3-1, 006	A

Table 3.3.2-12: 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 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.2.3.24)	VII.F1.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.2.3.24)	VII.F1.AP-221c	3.3-1, 006	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.3.2-13: Waste Management – Summary 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
Cleanout plug	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
Cleanout plug	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
Cleanout plug	Pressure boundary	Carbon steel	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3-1, 091	A
Cleanout plug	Pressure boundary	Carbon steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1
Cleanout plug	Pressure boundary	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-13: Waste Management – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Cleanout plug	Pressure boundary	Copper alloy	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-272	3.3-1, 095	A
Cleanout plug	Pressure boundary	Copper alloy	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1
Drain	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
Drain	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
Drain	Pressure boundary	Stainless steel	Concrete (ext)	None	None	VII.J.AP-19	3.3-1, 202	A
Drain	Pressure boundary	Stainless steel	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3-1, 095	A
Drain	Pressure boundary	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-13: Waste Management – Summary 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 cover	Filter	Copper alloy	Air – indoor uncontrolled (ext)	None	None	VII.J.AP-144	3.3-1, 114	A
Drain cover	Filter	Copper alloy	Air – indoor uncontrolled (int)	None	None	VII.J.AP-144	3.3-1, 114	A
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
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	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3-1, 095	A
Orifice	Pressure boundary	Stainless steel	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1
Orifice	Throttle	Stainless steel	Waste water (int)	Loss of material Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3-1, 095	A

Table 3.3.2-13: Waste Management – Summary 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	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1
Orifice (Unit 1 only)	Pressure boundary	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Orifice (Unit 1 only)	Throttle	Stainless steel	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A
Piping	Leakage boundary (spatial)	Copper alloy	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3-1, 095	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 3.3.2-13: Waste Management – Summary 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.2.3.24)	V.A.E-29	3.2-1, 044	A
Piping	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
Piping	Pressure boundary	Copper alloy	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1
Piping	Pressure boundary	Nickel alloy	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.C1.AP-221c	3.3-1, 006	A
Piping	Pressure boundary	Nickel alloy	Air – indoor uncontrolled (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.AP-221c	3.3-1, 006	A
Piping	Pressure boundary	Nickel alloy	Gas (int)	None	None	-	-	F, 2
Piping	Pressure boundary	Stainless steel	Air – indoor uncontrolled (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.AP-209c	3.3-1, 004	A

Table 3.3.2-13: Waste Management – Summary 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.2.3.24)	VII.C1.AP-221c	3.3-1, 006	A
Piping	Pressure boundary	Stainless steel	Concrete (ext)	None	None	VII.J.AP-19	3.3-1, 202	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)	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	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	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.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	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	A

Table 3.3.2-13: Waste Management – Summary 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	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1
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
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	Waste water (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3-1, 095	A

Table 3.3.2-13: Waste Management – Summary 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)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	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
Valve body	Pressure boundary	Carbon steel	Gas (int)	None	None	VII.J.AP-6	3.3-1, 121	A
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	Gas (int)	None	None	VII.J.AP-22	3.3-1, 120	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.2.3.24)	VII.E5.AP-278	3.3-1, 095	A

Table 3.3.2-13: Waste Management – Summary 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	Waste water (int)	Wall thinning – erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1

General Notes

A. Consistent with component, 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.
F. Material not in NUREG-2191 for this component.

Plant Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage the wall thinning due to erosion aging effect.
2. Nickel alloy is not subject to aging effects in a nitrogen gas environment.

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, which are addressed in this section are described in the indicated sections.

- Main Steam (2.3.4.1)
- Main Feedwater and Steam Generator Blowdown (2.3.4.2)
- Auxiliary Feedwater and Condensate (2.3.4.3)

3.4.2 Results

Table 3.4.2-1, Main Steam – Summary of Aging Management Evaluation

Table 3.4.2-2, Main Feedwater and Steam Generator Blowdown – Summary of Aging Management Evaluation

Table 3.4.2-3, Auxiliary Feedwater and Condensate – 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 Steam

Materials

The materials of construction for the main steam, auxiliary steam, and turbine systems components are:

- Carbon steel
- Copper alloy >15% Zn
- High-strength steel
- Low-alloy steel
- Nickel alloy
- Stainless steel
- Steel

Environments

The main steam, auxiliary steam, and turbine system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage

- Gas
- Steam
- Treated water >140°F
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the main steam, auxiliary steam, and turbine systems 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 steam, auxiliary steam, and turbine 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)
- Flow-Accelerated Corrosion (B.2.3.8)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.4.2.1.2 Main Feedwater and Steam Generator Blowdown

Materials

The materials of construction for the feedwater and blowdown system components are:

- Aluminum
- Carbon steel
- Gray cast iron
- Low-alloy steel
- Stainless steel
- Steel

Environments

The feedwater and blowdown system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Gas
- Treated water >140°F
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the feedwater and blowdown systems 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 blowdown 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)
- 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 and Condensate

Materials

The materials of construction for the auxiliary feedwater and condensate system components are:

- Carbon steel
- Coating
- Glass
- Stainless steel

Environments

The auxiliary feedwater and condensate system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Gas
- Lubricating oil
- Soil
- Steam
- Treated water >140°F
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the auxiliary feedwater and condensate systems require management:

- Cracking
- Cumulative fatigue damage
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning – erosion
- Wall thinning – FAC

Aging Management Programs

The following AMPs manage the aging effects for the auxiliary feedwater and condensate system components:

- Bolting Integrity (B.2.3.9)
- Buried and Underground Piping and Tanks (B.2.3.27)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.8)
- Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping components, Heat Exchangers, and Tanks (B.2.3.28)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)
- Water Chemistry (B.2.3.2)

3.4.2.2 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 System components, as described in SRP-SLR Item 3.4.2.2.1, is addressed as a TLAA in Section 4.3.2, "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 SS piping and piping components are exposed to uncontrolled indoor air and outdoor air. A review of PSL OE confirms that halides are potentially present in the uncontrolled indoor air environment at PSL. Additionally, insulated piping and components located in uncontrolled indoor air, 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 SS 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 SS components in the Steam Power and Conversion Systems. The External Surfaces Monitoring of

Mechanical Components and Bolting Integrity AMPs are described in Sections B.2.3.23 and B.2.3.9 respectively. There are no SS components exposed to an underground environment in the Steam and Power Conversion Systems.

3.4.2.2.3 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, 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 SS piping and piping components are exposed to uncontrolled indoor air and outdoor air. A review of PSL OE confirms the potential presence of halides in the indoor environment at PSL. Additionally, insulated piping and components located in uncontrolled indoor air, 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 SS 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. Additionally, there are no SS piping components exposed to an underground environment in the steam and power conversion systems.

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 uncontrolled 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 coating/linings on SS components in the Steam Power and Conversion System. Conditions will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The External Surfaces Monitoring of Mechanical Components and Bolting Integrity AMPs are described in Sections B.2.3.23 and B.2.3.9 respectively.

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 Sections 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 OE process and acceptance criteria are described in Sections 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.

PSL OE 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 in the Steam and Power Conversion systems; therefore, recurring internal corrosion is not an applicable aging effect at PSL. There is no need to augment the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP 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 outdoor air. A review of PSL OE confirms halides are potentially present in the outdoor air environment at PSL. 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 indoor uncontrolled 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. Conditions will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The External Surfaces Monitoring of Mechanical Components 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. There is no OE indicating degradation of the concrete that could lead to penetration of water to the metal surface, and the tanks are not exposed to groundwater. The Unit 1 CST and associated piping and components are protected on all sides by a concrete structural barrier. Since the top of the barrier provides minimal protection from weather, the Unit 1 CST and associated pipe and components are exposed to an outside environment. Site specific OE indicates there has been no degradation of the concrete that could lead to penetration of water to the metal surface, however it is conservatively assumed that water can penetrate under the surface of the tank. The Unit 2 CST and associated piping and components are located in a separate CST building, a structural missile barrier, which provides protection from weather. Therefore, loss of material of steel exposed to concrete for the Unit 2 CST is not an applicable aging effect but is an applicable aging effect for the Unit 1 CST. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material of the steel Unit 1 CST. Stainless steel piping exposed to soil or concrete are assumed to be subject to wetting and the Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage loss of material and cracking. The Outdoor and Large Atmospheric Metallic Storage Tanks and Buried and Underground Piping and Tanks AMPs are described in Sections B.2.3.17 and B.2.3.27, respectively.

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.

The Steam and Power Systems contain aluminum piping components exposed to outdoor air. A review of PSL OE confirms halides are potentially present in the air environments at PSL. As such, all aluminum components exposed to outdoor 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) AMP for components exposed to air internally or externally, respectively. 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. Conditions will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The External Surfaces Monitoring of Mechanical Components AMP is described in Sections B.2.3.23.

3.4.2.3 Time-Limited Aging Analysis

The TLAAs identified below are associated with the Steam and Power Conversion System components:

- Section 4.3, "Metal Fatigue"

3.4.3 Conclusion

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 System 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 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 3.4-1: 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)	Consistent with NUREG-2191. 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 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 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 AMP is used to manage wall thinning of steel piping, piping components, and heat exchanger channel heads exposed to steam or treated water.
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 AMP is used to manage loss of preload of metallic closure bolting in an indoor uncontrolled air and outdoor 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	Consistent with NUREG-2191. The Bolting Integrity AMP is used to manage cracking of high-strength steel closure bolting exposed to air. Cracking of stainless steel bolting is addressed by line item 3.4-1, 073.

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, 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 AMP is used to manage loss of material of stainless steel and carbon steel closure bolting exposed to uncontrolled air and outdoor 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. The Water Chemistry and One-Time Inspection AMPs are used to manage cracking of stainless steel piping, piping components, pump casings, and heat exchanger components exposed to steam or treated water >60°C (>140°F).
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. This item is used for vortex breakers. The Water Chemistry and One-Time Inspection AMPs are used to manage the vortex breakers exposed to 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. The Water Chemistry and One-Time Inspection AMPs are used to manage steel piping, piping components, and the turbine casing exposed to steam or treated water.
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. The Water Chemistry and One-Time Inspection AMPs are used to manage steel heat exchanger components exposed to 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. This line item is used for piping components in the Auxiliary Systems. The Water Chemistry and One-Time Inspection AMPs are used to manage loss of material of copper alloy piping components exposed to 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, 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. The Water Chemistry and One-Time Inspection 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.
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 applicable. There are no copper alloy or 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.
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. There are no steel heat exchanger components exposed to closed-cycle cooling water. Stainless steel heat exchanger components exposed to treated water are managed by line item 3.4-1, 015 and managed using the Water Chemistry and One-Time Inspection 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. There are no stainless steel heat exchanger components exposed to closed-cycle cooling water in the Steam and Power Conversion Systems.
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	Consistent with NUREG-2191 with exception. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP in the is used to manage loss of material for the condensate storage tanks exposed to air.
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.

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, 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. The Selective Leaching AMP is used to manage loss of material of gray cast iron piping and piping components 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. The External Surfaces Monitoring of Mechanical Components AMP is used to manage the loss of material in steel surfaces exposed to air.
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 AMP is used to manage loss of material for aluminum piping components exposed to air. Further evaluation is documented in Section 3.4.2.2.9.

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, 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	Consistent with NUREG-2191. This item is also used for turbine casings. The Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components AMP is used to manage the loss of material in steel piping, piping components, and turbine casings exposed to air.
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	There are no components within the scope of the GL 89-13 program in the Steam and Power Conversion Systems.
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	Consistent with NUREG-2191. This item is also used for tanks and pump casings. The Lubricating Oil Analysis and One-Time Inspection AMPs are used to manage the loss of material in steel piping, piping components, tanks, and pump casings exposed to lubricating oil.
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 and One-Time Inspection 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.

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, 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 piping or piping components exposed to lubricating oil in the Steam and Power Conversion Systems.
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 and One-Time Inspection AMPs are used to manage the loss of material in stainless steel 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 and One-Time Inspection 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	Consistent with NUREG-2191. This item is used for components in the Auxiliary Systems. The Buried and Underground Piping and Tanks AMP is used to manage loss of material in stainless steel piping exposed to soil or concrete.
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 exposed to soil or concrete.
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 steel piping and piping components exposed to soil, concrete, 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, 051	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Consistent with NUREG-2191. The Unit 2 carbon steel condensate storage tank exposed to concrete does not have aging effects because water does not have the potential to accumulate under the tank. 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	Consistent with NUREG-2191. The aluminum piping and piping components exposed to gas do not have any aging effects that require management.
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 or 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	Not applicable. There are no copper alloy piping and piping components exposed to air in the Steam and Power Conversion Systems. There are copper alloy > 15% Zn piping and piping components in the Steam and Power Conversion Systems. They are addressed by line item 3.4-1, 106.
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 lubricating oil 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 used. Boric acid corrosion is not an applicable aging effect for nickel alloy; the associated NUREG-2191 aging items are not used.

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, 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.
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 or controlled indoor air 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. This line item is also used for managing wall thinning due to erosion in pump casings and heat exchanger tubes and channel heads. The Flow-Accelerated Corrosion AMP is used to manage wall thinning due to erosion in metallic piping, piping components, and pump casings, and heat exchanger tubes 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 applicable. Based on a review of PSL OE, there are no instances of 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	Consistent with NUREG-2191 with exception. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP is used to manage loss of material for the steel condensate storage tanks.
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. The External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material of insulated steel, low-alloy steel 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	Consistent with NUREG-2191. Aging effect not applicable. Insulation for main steam and feedwater penetrations are fully encased in the multiple flued head and guard pipes and there are no plausible moisture, contaminants, or exposures that could degrade the (calcium silicate) insulation. Aging effects for non type-1 hot penetrations is addressed by line item 3.2-1, 087.

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 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 AMP 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, or 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	Consistent with NUREG-2191. This item is used for components in the Auxiliary Systems. The Buried and Underground Piping and Tanks AMP is used to manage cracking of stainless steel piping exposed to concrete or soil.
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 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 stainless steel underground components 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	Consistent with NUREG-2191. This line item is used for heat exchanger fins in the Auxiliary Systems. The External Surface Monitoring of Mechanical Components AMP is used to manage loss of material of copper alloy heat exchanger fins exposed to indoor uncontrolled air.
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	Not applicable. Long-term loss of material is not applicable for treated water systems in the Steam and Power Conversion Systems because corrosion inhibitors are used. There are no components subject to a raw water environment in the Steam and Power Systems.
3.4-1, 082	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Not used. While there are stainless steel piping components exposed to concrete, they are addressed by line items 3.4-1, 047 and 3.4-1, 072.
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	Not applicable. There are no stainless steel or nickel alloy tanks in the Steam and Power Conversion Systems.
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. The Water Chemistry and One-Time Inspection AMPs are used to manage loss of material of stainless steel piping and piping components exposed to steam.
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. The Water Chemistry and One-Time Inspection AMPs are used to manage loss of material in stainless steel piping, piping components, and heat exchanger tubes and tubesheets exposed to 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, 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.
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. This line item is used for pump casings in the Auxiliary Systems. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material in stainless steel pump casings 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	Not applicable. There are no steel, stainless steel, copper alloy heat exchanger tubes exposed to raw water in the Steam and Power Conversion Systems.
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	Not applicable. There are no stainless steel heat exchanger components exposed to raw water in the Steam and Power Conversion Systems.
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 stainless steel or nickel alloy underground 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 applicable. There are no stainless steel tanks in the Steam and Power Conversion Systems.
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 applicable. There are no stainless steel tanks in the Steam and Power Conversion Systems.
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 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 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, 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 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 AMP is used to manage cracking of copper alloy >15% Zn and copper alloy >8% Al 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 AMP is used to manage cracking of aluminum piping components exposed to air. Further evaluation is documented in Section 3.4.2.2.7.
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 exposed to soil or concrete 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 exposed to air with borated water leakage 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.
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.

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, 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. Boric acid corrosion is not an applicable aging effect for stainless steel; the associated NUREG-2191 aging items are not used.
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.
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 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	Carbon steel	Air – outdoor (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 – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VIII.H.SP-142	3.4-1, 006	A
Bolting	Mechanical closure	High-strength steel	Air – outdoor (ext)	Cracking	Bolting Integrity (B.2.3.9)	VIII.H.S-03	3.4-1, 007	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
Bolting	Mechanical closure	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity (B.2.3.9)	VIII.H.S-421	3.4-1, 073	A
Bolting	Mechanical closure	Stainless steel	Air – outdoor (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 – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VIII.H.SP-142	3.4-1, 006	A
Filter (Unit 2 only)	Filter	Stainless steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Filter (Unit 2 only)	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
Filter (Unit 2 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.A.SP-118b	3.4-1, 002	A

Table 3.4.2-1: Main 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**
Filter (Unit 2 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-127b	3.4-1, 003	A
Flexible hose (Unit 1 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.A.SP-118b	3.4-1, 002	A
Flexible hose (Unit 1 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-127b	3.4-1, 003	A
Flexible hose (Unit 1 only)	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A
Orifice (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
Orifice (Unit 1 only)	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	A
Orifice (Unit 1 only)	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	A
Orifice (Unit 1 only)	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 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 (Unit 2 only)	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
Orifice (Unit 2 only)	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
Orifice (Unit 2 only)	Throttle	Carbon steel	Air – dry (int)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Orifice (Unit 2 only)	Throttle	Nickel alloy	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-157	3.4-1, 084	A
Orifice (Unit 2 only)	Throttle	Nickel alloy	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	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 – outdoor (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	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	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

Table 3.4.2-1: Main 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	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	A
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.D1.S-16	3.4-1, 005	A
Piping	Pressure boundary	Low-alloy 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	A
Piping	Pressure boundary	Low-alloy 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	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	A
Piping	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
Piping	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
Piping	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.A.SP-118b	3.4-1, 002	A

Table 3.4.2-1: Main 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	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-127b	3.4-1, 003	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	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	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.B1.SP-87	3.4-1, 085	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.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.B1.SP-88	3.4-1, 011	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 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	Low-alloy 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	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 (insulated)	Pressure boundary	Stainless steel	Air – outdoor (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 – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A

Table 3.4.2-1: Main 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 (Unit 1 only)	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A
Piping and piping components	Pressure boundary	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, 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 4.3.2, Metal Fatigue of Non-Class 1 Components	VIII.B1.S-08	3.4-1, 001	A
Piping and piping components	Pressure boundary	Low-alloy steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Non-Class 1 Components	VIII.B1.S-08	3.4-1, 001	A
Piping and piping components	Pressure boundary	Low-alloy steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, 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 4.3.2, 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 4.3.2, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A

Table 3.4.2-1: Main 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)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B1.SP-71	3.4-1, 014	A
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)	Low-alloy 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	A
Piping and piping components	Structural integrity (attached)	Low-alloy 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 – 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 and piping components (insulated)	Structural integrity (attached)	Low-alloy 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 and piping components (Unit 11 only)	Structural integrity (attached)	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 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 (Unit 1 only)	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.A.SP-118b	3.4-1, 002	A
Piping and piping components (Unit 1 only)	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-127b	3.4-1, 003	A
Piping and piping components (Unit 1 only)	Structural integrity (attached)	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A
Steam 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	A
Steam trap	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
Steam trap	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-16	3.4-1, 005	A
Steam trap	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	A
Steam trap	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
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

Table 3.4.2-1: Main 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 (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
Steam trap (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
Steam trap (insulated)	Pressure boundary	Low-alloy 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
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 (insulated) (Unit 1 only)	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
Strainer (Unit 1 only)	Filter	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	A
Strainer (Unit 1 only)	Filter	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	A
Strainer (Unit 1 only)	Filter	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	A

Table 3.4.2-1: Main 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
Strainer (Unit 1 only)	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	A
Strainer (Unit 1 only)	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
Strainer (Unit 1 only)	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.D1.S-16	3.4-1, 005	A
Thermowell	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.A.SP-118b	3.4-1, 002	A
Thermowell	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.B1.SP-127b	3.4-1, 003	A
Thermowell	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	A
Thermowell	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	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 3.4.2-1: Main 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	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
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	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	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	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.D1.S-16	3.4-1, 005	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 – outdoor (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	Low-alloy 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	A

Table 3.4.2-1: Main 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	Low-alloy 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	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	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	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	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.A.SP-118b	3.4-1, 002	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (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	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	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

Table 3.4.2-1: Main 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	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	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	A
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.B1.SP-88	3.4-1, 011	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	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
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	Low-alloy 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

Table 3.4.2-1: Main 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	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
Valve body (insulated)	Pressure boundary	Stainless steel	Air – outdoor (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 – outdoor (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 (Unit 1 only)	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.4.2-2: Main Feedwater and Steam Generator Blowdown – Summary 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 – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Accumulator (Unit 1 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.SP-118b	3.4-1, 002	A
Accumulator (Unit 1 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.SP-127b	3.4-1, 003	A
Accumulator (Unit 1 Only)	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	Carbon steel	Air – outdoor (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 – outdoor (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 3.4.2-2: Main Feedwater and Steam Generator Blowdown – Summary 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)	VIII.H.S-421	3.4-1, 073	A
Bolting	Mechanical closure	Stainless steel	Air – outdoor (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 – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VIII.H.SP-142	3.4-1, 006	A
Filter (Unit 1 only)	Filter	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A
Filter (Unit 1 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.SP-118b	3.4-1, 002	A
Filter (Unit 1 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.SP-127b	3.4-1, 003	A
Filter (Unit 1 only)	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A
Flexible hose (Unit 1 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.SP-118b	3.4-1, 002	A
Flexible hose (Unit 1 only)	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.SP-127b	3.4-1, 003	A
Flexible hose (Unit 1 only)	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	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.D1.SP-87	3.4-1, 085	A
Orifice	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: Main Feedwater and Steam Generator Blowdown – Summary 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	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	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.D1.SP-87	3.4-1, 085	A
Orifice	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
Orifice	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	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
Orifice (insulated) (Unit 1 only)	Leakage boundary (spatial)	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
Orifice (Unit 1 only)	Leakage boundary (spatial)	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
Orifice (Unit 1 only)	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	A
Orifice (Unit 1 only)	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

Table 3.4.2-2: Main Feedwater and Steam Generator Blowdown – Summary 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 (Unit 1 only)	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	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	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
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	A
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	Air – outdoor (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 – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.SP-127b	3.4-1, 003	A

Table 3.4.2-2: Main Feedwater and Steam Generator Blowdown – Summary 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 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	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	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	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	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 (insulated) (Unit 1 only)	Leakage boundary (spatial)	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 (Unit 1 only)	Leakage boundary (spatial)	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 3.4.2-2: Main Feedwater and Steam Generator Blowdown – Summary 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 (Unit 1 only)	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	A
Piping (Unit 1 only)	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 (Unit 1 only)	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 (Unit 1 only)	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 (Unit 1 only)	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Non-Class 1 Components	VIII.D1.S-11	3.4-1, 001	A
Piping and piping components	Pressure boundary	Low-alloy steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, 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 4.3.2, 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	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, 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	A
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 (insulated)	Structural integrity (attached)	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

Table 3.4.2-2: Main Feedwater and Steam Generator Blowdown – Summary 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 (Unit 1 only)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Non-Class 1 Components	VIII.D1.S-11	3.4-1, 001	A
Piping and piping components (Unit 1 only)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Non-Class 1 Components	VII.E1.A-57	3.3-1, 002	A
Pump casing (Feedwater pumps 1A and 1B) (insulated) (Unit 1 only)	Leakage boundary (spatial)	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Pump casing (Feedwater pumps 1A and 1B) (insulated) (Unit 1 only)	Leakage boundary (spatial)	Stainless steel	Air – outdoor (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 (Feedwater pumps 1A and 1B) (Unit 1 only)	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	A
Pump casing (Feedwater pumps 1A and 1B) (Unit 1 only)	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
Pump casing (Feedwater pumps 1A and 1B) (Unit 1 only)	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	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
Steel components (Unit 1 only)	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
Thermowell	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

Table 3.4.2-2: Main Feedwater and Steam Generator Blowdown – Summary 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)	VIII.D1.SP-127b	3.4-1, 003	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.D1.SP-87	3.4-1, 085	A
Thermowell	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
Thermowell	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	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	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
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	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	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	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

Table 3.4.2-2: Main Feedwater and Steam Generator Blowdown – Summary 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)	VIII.D1.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.D1.SP-127b	3.4-1, 003	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.SP-118b	3.4-1, 002	A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.D1.SP-127b	3.4-1, 003	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	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
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	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	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

Table 3.4.2-2: Main Feedwater and Steam Generator Blowdown – Summary 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 – outdoor (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) (Unit 1 only)	Leakage boundary (spatial)	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
Valve body (insulated) (Unit 1 only)	Leakage boundary (spatial)	Gray cast iron	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
Valve body (insulated) (Unit 1 only)	Leakage boundary (spatial)	Low-alloy 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
Valve body (Unit 1 only)	Leakage boundary (spatial)	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
Valve body (Unit 1 only)	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	A
Valve body (Unit 1 only)	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 (Unit 1 only)	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 (Unit 1 only)	Leakage boundary (spatial)	Gray cast iron	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
Valve body (Unit 1 only)	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

Table 3.4.2-2: Main Feedwater and Steam Generator Blowdown – Summary 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 (Unit 1 only)	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	A
Valve body (Unit 1 only)	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 (Unit 1 only)	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
Valve body (Unit 1 only)	Leakage boundary (spatial)	Low-alloy 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
Valve body (Unit 1 only)	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.D1.SP-74	3.4-1, 014	A
Valve body (Unit 1 only)	Leakage boundary (spatial)	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 (Unit 1 only)	Pressure boundary	Aluminum	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-457c	3.4-1, 109	A
Valve body (Unit 1 only)	Pressure boundary	Aluminum	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.E.SP-147b	3.4-1, 035	A
Valve body (Unit 1 only)	Pressure boundary	Aluminum	Gas (int)	None	None	VIII.I.SP-23	3.4-1, 052	A
Valve body (Unit 1 only)	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 (Unit 1 only)	Pressure boundary	Stainless steel	Gas (int)	None	None	VIII.I.SP-15	3.4-1, 058	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.4.2-3: Auxiliary 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	Carbon steel	Air – outdoor (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 – outdoor (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
Bolting	Mechanical closure	Stainless steel	Air – outdoor (ext)	Cracking	Bolting Integrity (B.2.3.9)	VIII.H.S-421	3.4-1, 073	A
Bolting	Mechanical closure	Stainless steel	Air – outdoor (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 – outdoor (ext)	Loss of preload	Bolting Integrity (B.2.3.9)	VIII.H.SP-142	3.4-1, 006	A
Filter (Unit 2 only)	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, 1, 4
Filter (Unit 2 only)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A, 1, 4
Heat exchanger (lube oil cooler channel head) (Unit 2 only)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-40	3.3-1, 080	A, 1

Table 3.4.2-3: Auxiliary 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
Heat exchanger (lube oil cooler channel head) (Unit 2 only)	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	A, 1
Heat exchanger (lube oil cooler channel head) (Unit 2 only)	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	A, 1
Heat exchanger (lube oil cooler channel head) (Unit 2 only)	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-16	3.4-1, 005	A, 1
Heat exchanger (lube oil cooler shell) (Unit 2 only)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-40	3.3-1, 080	A, 1
Heat exchanger (lube oil cooler shell) (Unit 2 only)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-76	3.4-1, 041	A, 1
Heat exchanger (lube oil cooler tube sheet) (Unit 2 only)	Pressure boundary	Stainless steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-79	3.4-1, 044	A, 1
Heat exchanger (lube oil cooler tube sheet) (Unit 2 only)	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	A, 1
Heat exchanger (lube oil cooler tube sheet) (Unit 2 only)	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	A, 1
Heat exchanger (lube oil cooler tube sheet) (Unit 2 only)	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-88	3.4-1, 011	A, 1
Heat exchanger (lube oil cooler tubes) (Unit 2 only)	Heat transfer	Stainless steel	Lubricating oil (ext)	Reduction of heat transfer	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-102	3.4-1, 046	A, 1
Heat exchanger (lube oil cooler tubes) (Unit 2 only)	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.E.SP-96	3.4-1, 018	A, 1

Table 3.4.2-3: Auxiliary 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
Heat exchanger (lube oil cooler tubes) (Unit 2 only)	Pressure boundary	Stainless steel	Lubricating oil (ext)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-79	3.4-1, 044	A, 1
Heat exchanger (lube oil cooler tubes) (Unit 2 only)	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	A, 1
Heat exchanger (lube oil cooler tubes) (Unit 2 only)	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	A, 1
Heat exchanger (lube oil cooler tubes) (Unit 2 only)	Pressure boundary	Stainless steel	Treated water >140°F (int)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.G.SP-88	3.4-1, 011	A, 1
Orifice	Pressure boundary	Stainless steel	Air – outdoor (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 – outdoor (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	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	A
Orifice	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	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	A
Orifice	Throttle	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	A
Orifice (insulated) (Unit 1 only)	Leakage boundary (spatial)	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Orifice (insulated) (Unit 1 only)	Leakage boundary (spatial)	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-451c	3.4-1, 103	A
Orifice (Unit 1 only)	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-87	3.4-1, 085	A

Table 3.4.2-3: Auxiliary 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 (Unit 1 only)	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	A
Orifice (Unit 1 only)	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.E.SP-88	3.4-1, 011	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	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
Piping	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.G.SP-59	3.4-1, 036	A
Piping	Pressure boundary	Carbon steel	Gas (int)	None	None	VIII.I.SP-4	3.4-1, 059	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.E.SP-73	3.4-1, 014	A
Piping	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.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.G.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.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	Air – outdoor (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 – outdoor (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 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	Stainless steel	Concrete (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VIII.H.S-420	3.4-1, 072	A
Piping	Pressure boundary	Stainless steel	Concrete (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VIII.H.SP-145	3.4-1, 047	A
Piping	Pressure boundary	Stainless steel	Soil (ext)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VIII.H.S-420	3.4-1, 072	A
Piping	Pressure boundary	Stainless steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VIII.H.SP-145	3.4-1, 047	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.G.SP-87	3.4-1, 085	A
Piping	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.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.G.SP-88	3.4-1, 011	A
Piping (insulated)	Pressure boundary	Stainless steel	Air – outdoor (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 – outdoor (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) (Unit 1 only)	Leakage boundary (spatial)	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 (Unit 1 only)	Leakage boundary (spatial)	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
Piping (Unit 1 only)	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	A
Piping (Unit 1 only)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	A
Piping (Unit 1 only)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-16	3.4-1, 005	A

Table 3.4.2-3: Auxiliary 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 (Unit 2 only)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A, 1
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, 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 4.3.2, Metal Fatigue of Non-Class 1 Components	VIII.G.S-11	3.4-1, 001	A
Piping and piping components	Pressure boundary	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, 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	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
Piping and piping components	Structural integrity (attached)	Carbon steel	Gas (int)	None	None	VIII.I.SP-4	3.4-1, 059	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Non-Class 1 Components	VIII.G.S-11	3.4-1, 001	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.A.SP-71	3.4-1, 014	A
Piping and piping components	Structural integrity (attached)	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.A.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.G.S-16	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.G.SP-74	3.4-1, 014	A

Table 3.4.2-3: Auxiliary 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.G.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.G.S-16	3.4-1, 005	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, 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 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	A
Piping and piping components	Structural integrity (attached)	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	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.G.SP-88	3.4-1, 011	A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-452c	3.4-1, 104	A
Piping and piping components (insulated)	Structural integrity (attached)	Stainless steel	Air – outdoor (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 (Unit 1 only)	Structural integrity (attached)	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.G.SP-59	3.4-1, 036	A
Piping and piping components (Unit 2 only)	Pressure boundary	Carbon steel	Steam (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Non-Class 1 Components	VIII.G.S-11	3.4-1, 001	A, 2
Piping and piping components (Unit 2 only)	Structural integrity (attached)	Carbon steel	Treated water (int)	Cumulative fatigue damage	TLAA – Section 4.3.2, Metal Fatigue of Non-Class 1 Components	VIII.G.S-11	3.4-1, 001	A

Table 3.4.2-3: Auxiliary 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**
Pump casing (auxiliary feedwater lube oil) (Unit 2 only)	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
Pump casing (auxiliary feedwater lube oil) (Unit 2 only)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A, 1
Pump casing (auxiliary feedwater pump)	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
Pump casing (auxiliary feedwater pump)	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	A
Pump casing (auxiliary feedwater pump)	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	A
Sight glass (Unit 2 only)	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, 1
Sight glass (Unit 2 only)	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.G.SP-59	3.4-1, 036	A, 1
Sight glass (Unit 2 only)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A, 1
Sight glass (Unit 2 only)	Pressure boundary	Glass	Air – outdoor (ext)	None	None	VIII.I.SP-33	3.4-1, 055	A, 1
Sight glass (Unit 2 only)	Pressure boundary	Glass	Air – outdoor (int)	None	None	VIII.I.SP-33	3.4-1, 055	A, 1
Sight glass (Unit 2 only)	Pressure boundary	Glass	Lubricating oil (int)	None	None	VIII.I.SP-10	3.4-1, 055	A, 1
Tank (condensate storage tank)	Pressure boundary	Carbon steel	Gas (int)	None	None	VIII.I.SP-4	3.4-1, 059	A

Table 3.4.2-3: Auxiliary 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
Tank (condensate storage tank)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VIII.E.S-405	3.4-1, 062	B
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.E.S-401	3.4-1, 066	B
Tank (condensate storage tank) (Unit 1 only)	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VIII.E.SP-115	3.4-1, 030	B, 3
Tank (condensate storage tank) (Unit 1 only)	Pressure boundary	Carbon steel	Concrete (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VIII.E.SP-115	3.4-1, 030	B, 3
Tank (condensate storage tank) (Unit 2 only)	Pressure boundary	Carbon steel	Air – indoor uncontrolled (ext)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VIII.E.SP-115	3.4-1, 030	B, 3
Tank (condensate storage tank) (Unit 2 only)	Pressure boundary	Carbon steel	Concrete (ext)	None	None	VIII.I.SP-154	3.4-1, 051	A
Tank (lube oil reservoir) (Unit 2 only)	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, 1
Tank (lube oil reservoir) (Unit 2 only)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A, 1
Turbine casing	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, 2
Turbine casing (Unit 1 only)	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.G.SP-59	3.4-1, 036	A, 2
Turbine casing (Unit 2 only)	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.A.SP-71	3.4-1, 014	A, 2
Turbine casing (Unit 2 only)	Pressure boundary	Carbon steel	Steam (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.A.S-408	3.4-1, 060	A, 2

Table 3.4.2-3: Auxiliary 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**
Turbine casing (Unit 2 only)	Pressure boundary	Carbon steel	Steam (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.A.S-15	3.4-1, 005	A, 2
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	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
Valve body	Pressure boundary	Carbon steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.G.SP-59	3.4-1, 036	A
Valve body	Pressure boundary	Carbon steel	Gas (int)	None	None	VIII.I.SP-4	3.4-1, 059	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.E.SP-73	3.4-1, 014	A
Valve body	Pressure boundary	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.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.G.S-16	3.4-1, 005	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	Air – outdoor (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 – outdoor (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	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	A
Valve body	Pressure boundary	Stainless steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	A

Table 3.4.2-3: Auxiliary 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.G.SP-88	3.4-1, 011	A
Valve body (insulated)	Pressure boundary	Stainless steel	Air – outdoor (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 – outdoor (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) (Unit 1 only)	Leakage boundary (spatial)	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
Valve body (Unit 1 only)	Leakage boundary (spatial)	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
Valve body (Unit 1 only)	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	A
Valve body (Unit 1 only)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – erosion	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-408	3.4-1, 060	A
Valve body (Unit 1 only)	Leakage boundary (spatial)	Carbon steel	Treated water (int)	Wall thinning – FAC	Flow-Accelerated Corrosion (B.2.3.8)	VIII.G.S-16	3.4-1, 005	A
Valve body (Unit 2 only)	Pressure boundary	Carbon steel	Lubricating oil (int)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A, 1
Vortex breaker	Vortex prevention	Carbon steel	Treated water (ext)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4-1, 012	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. Unit 1 does not have an external lube oil cooler. Cooling water is provided to the bearings by water from the condensate system. Heat is dissipated through externally mounted fins.
2. During standby, steam to the Unit 1 auxiliary feedwater turbine is isolated, and the turbine is open to the atmosphere with an internal environment of air. During standby, the Unit 2 auxiliary feedwater turbine receives steam continuously to maintain turbine warm-up conditions.
3. The Unit 1 condensate storage tank is partially enclosed in a concrete missile barrier. The Unit 2 condensate storage tank is completely enclosed in a concrete missile barrier.
4. The filtering component is not long lived and the filtering function is therefore not included.

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 Building Structures (2.4.1)
- Component Cooling Water Areas (2.4.2)
- Condensate Polisher Building (2.4.3)
- Condensate Storage Tank Enclosures (2.4.4)
- Diesel Oil Equipment Enclosures (2.4.5)
- Emergency Diesel Generator Buildings (2.4.6)
- Fuel Handling Buildings (2.4.7)
- Intake, Discharge, and Emergency Cooling Canals (2.4.8)
- Intake Structures (2.4.9)
- Reactor Auxiliary Buildings (2.4.10)
- Steam Trestle Areas (2.4.11)
- Switchyard and Switchyard Control Building (2.4.12)
- Turbine Buildings (2.4.13)
- Ultimate Heat Sink Dam (Barrier Wall) (2.4.14)
- Yard Structures (2.4.15)
- Component Support Commodity (2.4.16)
- Fire Rated Assemblies (2.4.17)
- Overhead Heavy Load Handling Systems (2.4.18)

3.5.2 Results

Table 3.5.2-1, Containment Building Structures – Summary of Aging Management Evaluation

Table 3.5.2-2, Component Cooling Water Areas – Summary of Aging Management Evaluation

Table 3.5.2-3, Condensate Polisher Building – Summary of Aging Management Evaluation

Table 3.5.2-4, Condensate Storage Tank Enclosures – Summary of Aging Management Evaluation

Table 3.5.2-5, Diesel Oil Equipment Enclosures – Summary of Aging Management Evaluation

Table 3.5.2-6, Emergency Diesel Generator Buildings – Summary of Aging Management Evaluation

Table 3.5.2-7, Fuel Handling Buildings – Summary of Aging Management Evaluation

Table 3.5.2-8, Intake, Discharge, and Emergency Cooling Canals – Summary of Aging Management Evaluation

Table 3.5.2-9, Intake Structures – Summary of Aging Management Evaluation

Table 3.5.2-10, Reactor Auxiliary Buildings – Summary of Aging Management Evaluation

Table 3.5.2-11, Steam Trestle Areas – Summary of Aging Management Evaluation

Table 3.5.2-12, Switchyard and Switchyard Control Building – Summary of Aging Management Evaluation

Table 3.5.2-13, Turbine Buildings – Summary of Aging Management Evaluation

Table 3.5.2-14, Ultimate Heat Sink Dam (Barrier Wall) – Summary of Aging Management Evaluation

Table 3.5.2-15, Yard Structures – Summary of Aging Management Evaluation

Table 3.5.2-16, Component Support Commodity – Summary of Aging Management Evaluation

Table 3.5.2-17, Fire Rated Assemblies – Summary of Aging Management Evaluation

Table 3.5.2-18, Overhead Heavy Load Handling Systems – 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 Building Structures

Materials

The materials of construction for the containment building structures (containment vessel, penetrations, and shield building) and internal structural components are:

- Calcium Silicate
- Coatings
- Concrete
- Concrete (reinforced)
- Concrete block (reinforced, unreinforced)
- Dissimilar metal welds
- Elastomer
- Galvanized steel

- Lubrite®
- Nickel alloy
- Silicone
- Stainless steel
- Steel

Environments

The containment building structures (containment vessel, penetrations, and shield building) and internal structural components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- 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 building structures (containment vessel, penetrations, and shield building) 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 fracture toughness
- Loss of leak tightness
- Loss of material
- Loss of mechanical function
- Loss of mechanical properties
- Loss of preload
- 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 building structures (containment vessel, penetrations, and shield building) and internal structural components.

- 10 CFR Part 50, Appendix J (B.2.3.31)
- ASME Section XI, Subsection IWE (B.2.3.29)
- ASME Section XI, Subsection IWF (B.2.3.30)

- Boric Acid Corrosion (B.2.3.4)
- Masonry Walls (B.2.3.32)
- One Time Inspection (B.2.3.20)
- Protective Coating Monitoring and Maintenance (B.2.3.35)
- Structures Monitoring (B.2.3.33)
- Water Chemistry (B.2.3.2)

3.5.2.1.2 Component Cooling Water Areas

Materials

The materials of construction for the component cooling water area components are:

- Concrete (reinforced)
- Galvanized steel
- Steel

Environments

The component cooling water area 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 component cooling water areas 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 component cooling water area components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.3 Condensate Polisher Building

Materials

The materials of construction for the condensate polisher building components are:

- Concrete (reinforced)

Environments

The condensate polisher building 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 condensate polisher building require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of strength

Aging Management Programs

The following AMPs manage the aging effects for the condensate polisher building components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.4 Condensate Storage Tank Enclosures

Materials

The materials of construction for the condensate storage tank enclosure components are:

- Concrete (reinforced)
- Galvanized steel
- Steel

Environments

The condensate storage tank enclosure 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 condensate storage tank enclosures 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 condensate storage tank enclosure components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.5 Diesel Oil Equipment Enclosures

Materials

The materials of construction for the diesel oil equipment enclosure components are:

- Concrete (reinforced)
- Galvanized steel
- Steel

Environments

The diesel oil equipment enclosure 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 diesel oil equipment enclosures 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 diesel oil equipment enclosure components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.6 Emergency Diesel Generator Buildings

Materials

The materials of construction for the emergency diesel generator building components are:

- Concrete (reinforced)
- Galvanized steel
- Steel

Environments

The emergency diesel generator building 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 emergency diesel generator buildings 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 emergency diesel generator building components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.7 Fuel Handling Buildings

Materials

The materials of construction for the fuel handling building components are:

- Aluminum alloy
- Boron carbide
- Caulking and Sealants
- Concrete block (reinforced, unreinforced)
- Concrete (reinforced, unreinforced)
- Galvanized steel
- Stainless Steel
- Steel
- 6061 aluminum alloy reinforced w/ type 1 ASTM C-750 boron carbide

Environments

The fuel handling building components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater / soil
- Soil
- Treated borated water
- Water – flowing

Aging Effects Requiring Management

The following aging effects associated with the fuel handling buildings require management:

- Change in dimensions
- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction in neutron-absorbing capacity

Aging Management Programs

The following AMPs manage the aging effects for the fuel handling building components:

- Boric Acid Corrosion (B.2.3.4)
- Masonry Walls (B.2.3.32)
- Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.3.26)
- One-Time Inspection (B.2.3.20)
- Structures Monitoring (B.2.3.33)
- Water Chemistry (B.2.3.2)

3.5.2.1.8 Intake, Discharge, and Emergency Cooling Canals

Materials

The materials of construction for the intake, discharge, and emergency cooling canal components are:

- Concrete (reinforced)
- Grout
- Earthen fill

Environments

The intake, discharge, and emergency cooling canal components are exposed to the following environments:

- Air – outdoor
- Groundwater / soil
- Raw water
- Soil
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects associated with the intake, discharge, and emergency cooling canals require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of form
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the intake, discharge, and emergency cooling canal components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)
- Structures Monitoring (B.2.3.33)

3.5.2.1.9 Intake Structures

Materials

The materials of construction for the intake structure components are:

- Caulking and sealants
- Concrete (reinforced)
- Galvanized steel
- PVC
- Stainless steel
- Steel

Environments

The intake structure components are exposed to the following environments:

- Air – outdoor
- Concrete
- Groundwater / soil
- Raw water
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects associated with the intake structures 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 intake structure components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)
- Structures Monitoring (B.2.3.33)

3.5.2.1.10 Reactor Auxiliary Buildings

Materials

The materials of construction for the reactor auxiliary building components are:

- Caulking and sealants
- Concrete (reinforced)
- Concrete (unreinforced)
- Concrete block (reinforced, unreinforced)
- Elastomers
- Galvanized steel
- Stainless steel
- Steel

Environments

The reactor auxiliary building components are exposed to the following environments:

- Air – indoor controlled
- 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 reactor auxiliary buildings 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 reactor auxiliary building components:

- Boric Acid Corrosion (B.2.3.4)
- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.11 Steam Trestle Areas

Materials

The materials of construction for the steam trestle area components are:

- Concrete (reinforced)
- Galvanized steel
- Steel

Environments

The steam trestle area components are exposed to the following environments:

- Air – outdoor
- Groundwater / soil
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects associated with the steam trestle areas 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 steam trestle area components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.12 Switchyard

Materials

The materials of construction for the switchyard components are:

- Caulking and sealants
- Concrete (reinforced)
- Concrete block (reinforced)
- Steel (galvanized steel)

Environments

The switchyard 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 switchyard 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 switchyard components:

- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.13 Turbine Buildings

Materials

The materials of construction for the turbine building components are:

- Caulking and sealants
- Concrete (reinforced)
- Concrete block (unreinforced)
- Steel

Environments

The turbine building 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 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 turbine building components:

- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.14 Ultimate Heat Sink Dam (Barrier Wall)

Materials

The materials of construction for the ultimate heat sink (barrier wall) components are:

- Concrete (reinforced)
- Galvanized steel
- Steel

Environments

The ultimate heat sink (barrier wall) components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater / soil
- Raw water
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects associated with the ultimate heat sink (barrier wall) 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 ultimate heat sink (barrier wall) components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)
- Structures Monitoring (B.2.3.33)

3.5.2.1.15 Yard Structures

Materials

The materials of construction for the yard structure components are:

- Caulking and sealants
- Concrete (reinforced)
- Galvanized steel
- Steel

Environments

The yard structure components are exposed to the following environments:

- Air – outdoor
- Concrete
- Groundwater / soil
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects associated with the yard structures 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 yard structure components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.16 Component Support Commodity

Materials

The materials of construction for the component support commodity components are:

- Aluminum
- Calcium silicate
- Concrete (reinforced)
- Galvanized steel

- Graphite
- Grout
- High-strength steel
- Non-metallic, elastomer
- PVC
- Stainless steel
- Steel

Environments

The component support commodity components are exposed to the following environments:

- Air
- Air – indoor controlled
- 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 mechanical function
- Loss of preload
- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects for the component support commodity components:

- ASME Section XI, Subsection IWF (B.2.3.30)
- Boric Acid Corrosion (B.2.3.4)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Structures Monitoring (B.2.3.33)

3.5.2.1.17 Fire Rated Assemblies

Materials

The materials of construction for the fire rated assembly components are:

- Aluminum
- Cementitious coatings: quelpyre mastic 703B
- Ceramic fiber
- Ceramic fiber/stainless steel sheet metal (panels)

- Fire retardant coating
- Galvanized steel
- Elastomer
- Elastomer: dymeric sealant, ethafoam
- Insulating blankets (B&B or Mecatiss)
- Marinite board
- Silicate: ceramic fiber
- Silicates: cerablanket
- Silicone
- Silicone foam
- Stainless steel
- Steel
- Subliming compound: thermo-lag 330-1, thermo-lag 770-1

Environments

The fire rated assembly components are exposed to the following environments:

- Air
- Air – indoor controlled
- Air – indoor uncontrolled

Aging Effects Requiring Management

The following aging effects associated with the fire rated assemblies require management:

- Change in material properties
- Cracking
- Delamination
- Hardening
- Loss of material
- Loss of strength
- Separation
- Shrinkage

Aging Management Programs

The following AMPs manage the aging effects for the fire rated assembly components:

- Fire Protection (B.2.3.15)

3.5.2.1.18 Overhead Heavy Load Handling Systems

Materials

The materials of construction for the Overhead Heavy Load Handling System components are:

- Concrete (reinforced)
- Galvanized steel
- Steel

Environments

The Overhead Heavy Load Handling System 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 Overhead Heavy Load Handling Systems require management:

- Cracking
- Cumulative fatigue damage
- 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 Overhead Heavy Load Handling System components:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13)
- Structures Monitoring (B.2.3.33)

3.5.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL Report

NUREG-2192 provides the basis for those AMPs / topics that warrant further evaluation by the reviewer in the SLRA. For the containment and plant structures and 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 Pressurized Water Reactor and Boiling Water Reactor Containments

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.

Further evaluation is recommended of aging management of (1) cracking and distortion due to increases in component stress levels from settlement for PWR and BWR concrete and steel containments and (2) reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundations for all types of PWR and BWR containments if a dewatering system is relied upon to control settlement. If a plant's CLB credits a dewatering system to control settlement, then a commitment to monitor the functionality of the dewatering system under ASME Code Section XI, Subsection IWL or the structures monitoring program during the SPEO is provided or a plant-specific program is credited with monitoring the dewatering system during the SPEO.

Cracks, distortion, and increase in component stresses due to settlement of concrete foundations are considered in the Structures Monitoring (B.2.3.33) AMP. The PSL Shield Building concrete foundation/base mat reinforcement is billet steel conforming to ASTM A615-68. Cracking is typically manifested in concrete structural components as complete or incomplete separation. The steel reinforcement is placed in the concrete walls, dome and foundation (of the PSL Shield Building) to control cracking due to concrete shrinkage and temperature gradients. The PSL Unit 1 containment structure is founded on compacted Class I fill consisting of clean sand and gravel with a maximum of 12% fines. For Unit 2, the original deposits at the plant site were excavated, backfilled with Class I fill which consisted of select sand having no more than 15% silt content and no rock fragments larger than 6 inches. After initial settlement occurred, the settlement ceased, no further significant settlement has occurred, and no further significant structural settlement is expected. Cracking, distortion, and an increase in component stress levels due to settlement are not probable aging effects at PSL. However, the Structures Monitoring (B.2.3.33) AMP monitors for cracks and distortion and contains inspection criteria to verify these aging effects are not developing.

Reduction in foundation strength due to erosion of porous concrete subfoundations is not an aging effect requiring management at PSL. PSL's structure foundations are constructed of solid concrete and not the subject porous type. Dewatering system was used during construction at the PSL site but there is no permanent dewatering system. The inaccessible, below-grade foundations are exposed to groundwater, which is conservatively considered to be flowing water for SLR. Per NUREG-1779, fluctuations in the groundwater are influenced by tidal changes in the Atlantic Ocean to the east, moderated by the Indian River to the west. That notwithstanding, the Structures Monitoring (B.2.3.33) AMP monitors for settlement and cracking, as listed in Table 3.5.2-1.

The identification of indications of settlement by the Structures Monitoring (B.2.3.33) AMP, 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 to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI Subsection IWL and/or Structures Monitoring AMPs, essential to manage these aging effects for portion of the concrete containment components that exceed specified temperature limits {i.e., general area temperature greater than 66 degrees Celsius (150 degrees Fahrenheit) and local area temperature greater than 93 degrees Celsius (200 degrees Fahrenheit). 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 (License Renewal and Standardization Branch)-1, "Aging Management Review – Generic, July 2017" *(Appendix A.1 of this SRP-SLR).*

As described above, the PSL Units 1 and 2 containment building structures have an ASME Class MC Containment Vessel surrounded by a Shield Building, also known as Reactor Containment Building, with a 4 ft annulus separating the Containment Vessel and the Shield Building. As such, there are no concrete containments (ASME Class CC) that would be susceptible to a reduction of strength and modulus of elasticity due to elevated temperatures and the ASME Code Section XI Subsection IWL is not applicable at PSL. Elevated temperature impacts on PSL Shield Building concrete were addressed for the current renewed license in the PSL LRA. Localized hotspots are limited in area and are designed to be maintained below the degradation threshold temperature limits of the ACI standards.

The potential sources of localized heat environments at PSL Units 1 and 2 containment building structures are from Type I and Type III mechanical penetrations. Type I (hot) penetrations include main steam and feedwater lines which are designed to accommodate high thermal movements and temperature differentials. Type III (semi-hot) penetrations are designed to accommodate moderate thermal movements. Type III penetrations include blowdown, letdown, charging, safety injection, shutdown cooling, RCP bleed-off, and integrated leak rate test (ILRT) lines. Type I (hot) penetration assemblies are insulated to limit Containment Vessel nozzle thermal stresses that also serve to limit Shield Building concrete temperatures.

Furthermore, the OE review for SLR did not identify any instance of Shield Building concrete temperatures exceeding ACI standards. The specification for Containment penetration assemblies indicates that temperature imposed on the concrete shield wall, due to the fluid at design temperature in the process pipe shall not exceed 150°F. Therefore, a reduction of strength and modulus of elasticity due to elevated temperatures does not require management for the PSL Shield Building. Accordingly, a plant-specific AMP or corresponding enhancement of the Structures Monitoring (B.2.3.33) AMP is not required.

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).*

PSL is a PWR, therefore, torus ring girders and downcomers corrosion in a BWR, items 2) and 3) above, are not applicable. For item 1, corrosion in inaccessible areas of the containment steel in air and fluid at PSL was addressed for the current renewed licenses. At the time, pitting was observed on the Unit 2 containment vessel exterior in the vicinity of the annulus floor and the affected area was coated and follow-up inspections were performed. Secondly, degraded coatings and minor corrosion were observed at a piping penetration on Unit 2. The affected area was cleaned and recoated in accordance with plant procedures. The moisture barrier between the steel containment vessel and the concrete was observed to have cracked on Unit 2. Sealant material was removed, and the containment vessel was inspected. Minor corrosion was observed but no repairs were required.

In addition, the lower ~ 9 feet of the PSL Containment Vessel shell and bottom head are fully embedded in concrete fill, both inside and outside the Containment

Vessel in the Shield Building. The Containment Vessel bottom head is supported by concrete fill, with the void spaces filled. Concrete fill also occupies the operating floor inside the PSL Containment Vessel. Moisture barriers are provided between the Containment Vessel and concrete fill on the Shield Building side and inside the Containment Vessel. These moisture barriers are inspected by the Section XI, Subsection IWE Inservice Inspection Program for the current renewed licenses.

The ASME Section XI, Subsection IWE (B.2.3.29) AMP continues the ASME Section XI, Subsection IWE Inservice Inspection Program for SLR. The ASME Section XI, Subsection IWE (B.2.3.29) AMP includes inspections in accessible areas, such as penetration sleeves/assemblies, and considerations for inaccessible areas if degradation is detected in accessible areas. Therefore, and since the bottom of the Containment Vessel is fully embedded in concrete on both sides with a moisture barrier that is periodically inspected, a plant specific program to manage loss of material for inaccessible areas of containment vessel components is not required.

3.5.2.2.1.4. Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevation 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).

The PSL Units 1 and 2 Shield Building is a free-standing reinforced concrete structure which meets the requirements of ACI 318-63 and ACI 318-71. The PSL Shield Buildings do not include prestressed tendons. The concrete is reinforced with billet steel conforming to ASTM A615-68. As such, loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature is not an aging effect requiring management for the PSL Shield Building.

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.*

For the above-stated containment pressure-retaining components (corresponding to Table 3.5-1, Items 027 and 040) subject to cyclic loading for which no CLB fatigue analysis exists at the time of an SLRA submittal, a plant-specific further evaluation may be performed to demonstrate that cracking due to cyclic loading is an aging effect that does not require aging management for the component. As one acceptable approach, the aging effect does not require aging management actions if the further evaluation demonstrates that the six criteria for cyclic loading in paragraph NE-3222.4(d) (NE-3221.5(d) in 1980 and later code editions), "Analysis for Cyclic Operation, Vessels Not Requiring Analysis for Cyclic Service," of ASME Code, Section III, Division 1 (1974 edition or later edition incorporated by reference in 10 CFR 50.55a(a)(i)), that provide for a waiver from detailed fatigue analysis are satisfied for applicable component materials through the end of the subsequent period of extended operation. The option to perform a fatigue waiver analysis to address the aging effect of cracking due to cyclic loading, for specific containment metallic components, is in lieu of performing supplemental surface examinations or performing or crediting an appropriate 10 CFR Part 50, Appendix J, leak-rate test discussed in GALL-SLR Report AMP XI.S1, "ASME Section XI, Subsection IWE."

The PSL Units 1 and 2 Containment Vessels are designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III. For the current renewed licenses, the Containment Vessels' compliance with these design requirements precludes cyclic fatigue cracking that may result in leakage. However, compliance with leakage design criteria to ensure containment integrity is verified through periodic visual examination and testing in accordance with ASME Section XI, Subsection IWE, Inservice Inspection AMP and 10 CFR Part 50, Appendix J AMP.

The original PSL containment design analyses include a fatigue waiver for the Containment Vessels and fatigue analyses for the mechanical penetrations. However, there were no fatigue waivers or fatigue analyses for the equipment hatches, personnel hatches, and the electrical penetrations because these containment penetrations were not subject to cyclical loads. Therefore, there are no fatigue waivers or fatigue analyses for the equipment hatches, personnel hatches, and the electrical penetrations. However, cyclic loading evidenced as cracking for these non-piping penetrations at PSL will be managed for SLR by the enhanced ASME Section XI, Subsection IWE (B.2.3.29) AMP and 10 CFR Part 50, Appendix J (B.2.3.31) AMP.

Cumulative fatigue damage for the PSL mechanical penetrations was addressed for the current renewed licenses. It was demonstrated that, other than the safety injection penetrations which are ASME Class 1, penetration bellows at PSL Units 1 and 2 are specified to withstand a lifetime total of 7000 cycles of expansion and compression and that the Fatigue Monitoring (B.2.2.1) AMP (FMP) manages the safety injection penetrations and provides assurance that the other penetrations will not exceed the specified cycles, as summarized in UFSAR Sections 18.2.7 (Unit 1) and 18.3.4 (Unit 2).

For SLR, cumulative fatigue damage is also an aging effect requiring management for mechanical penetrations that is addressed in Section 4.6, "Containment Liner Plate," Metal Containments and Penetrations Fatigue.

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 current renewed licenses and determined not to require management for containment steel in air structural components. Typical details for containment piping and fuel transfer penetrations are provided in the Unit 1 UFSAR [Figure 3.8-9] and Unit 2 UFSAR [Figure 3.8-7]. These penetration assemblies (e.g., sleeves, flued heads, or caps), are carbon steel or SS depending on the system. The fuel transfer penetration is SS. The fuel transfer penetration includes (primary) bellows that function as barriers against leakage of refueling water from either the fuel transfer canal inside the fuel handling building or refueling cavity inside containment. Other penetration assemblies include secondary bellows. Stainless steel penetrations may involve dissimilar metal welds (DMWs) to the carbon steel vessel nozzle, penetration sleeve. Carbon steel is not susceptible to SCC.

The containment air temperature during normal plant operation is less than or equal to 120°F and localized temperatures at penetrations are less than 150°F by design. High temperature (Type I) penetration nozzles, bellows, and sleeves are carbon steel. Stainless steel penetrations, and any DMWs, associated with systems that are exposed to temperatures >140°F during normal operation may be susceptible to SCC. Penetrations with SS process lines that see temperatures > 140°F include those for:

- Letdown (#26),
- Hot Leg Sampling (#28),
- Safety injection (#36, #37, #38, #39, and #41), and
- Shutdown cooling (#40)

Conservatively, the SS fuel transfer tube penetration (#25) components are also susceptible to cracking due to SCC. The Containment Vessel nozzles for the above penetrations are carbon steel. As such, the penetrations are considered to include DMWs. Therefore, cracking of SS penetration components, and any DMWs, for nine (9) penetrations per Unit will be managed by the ASME Section XI, Subsection IWE (B.2.3.29) AMP, which includes enhancement for surface, or enhanced visual, examination to detect evidence of cracking in a representative sample of the penetrations.

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 to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL, and/or Structures Monitoring AMPs, to manage these aging effects for plants located in moderate to severe weathering conditions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Freeze-thaw of inaccessible areas of the concrete components of the PSL containment structure was addressed as part of the first license renewal effort. The reinforced concrete shield building and foundations conform to the applicable portions of ACI 318-63 for Unit 1 and ACI 318-71 for Unit 2.

PSL is not located in a severe weathering region with numerous freeze-thaw cycles and significant amounts of winter rainfall. PSL is located in a subtropical climate with long, warm summers accompanied by abundant rainfall and mild, dry winters with negligible freeze-thaw cycles. As such, same as for the current renewed licenses, cracking due to freeze-thaw is not an aging effect that requires management for PSL Shield Building and Containment internal concrete components. There is also no need for a plant specific AMP or plant-specific enhancement of the Structures Monitoring (B.2.3.33) AMP.

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 the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL, and/or Structures Monitoring AMPs 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 in support of the current renewed licenses. Cracking is manifested in concrete structural components as complete or incomplete separation of the concrete into two or more parts. The PSL concrete components were constructed using non-reactive aggregates whose acceptability was in accordance with ASTM C33. Consequently, cracking and expansion due to reaction with aggregates are not probable aging effects and have not been observed to date. Furthermore, reaction with aggregates has not been identified during walkdowns and inspections of concrete structures at PSL.

However, the Structures Monitoring (B.2.3.33) 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 alkali-carbonate reaction (ACR), and includes opportunistic inspection of inaccessible concrete locations. As such, a plant-specific program or plant-specific enhancement of the Structures Monitoring (B.2.3.33) AMP is not required to manage this aging effect; rather, inspections and evaluations performed in accordance with the Structures Monitoring (B.2.3.33) AMP will identify the presence of expansion and cracking due to reaction with aggregates should it occur.

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 to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL and/or Structures Monitoring AMPs, essential to manage these aging effects 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 in support of the current renewed licenses. Leaching of calcium hydroxide is observed on concrete that is alternatively wetted and dried. It 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. Consistent with the provisions of ACI requirements, the PSL Units 1 and 2 concrete structures and concrete structural components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-cement ratio that is characteristic of concrete having low permeability.

However, the containment structure foundation and lower portion of exterior walls are exposed to groundwater, which for SLR is considered to be flowing water. The groundwater at PSL site is characterized by high concentrations of chlorides and sulfates that create an aggressive environment for concrete structures. The Structures Monitoring (B.2.3.33) AMP will include plant specific enhancement that deals with inspections of accessible or below-grade inaccessible concrete structures exposed to aggressive groundwater/soil, on an interval not to exceed 5 years.

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.*

Further evaluation of inaccessible areas at PSL are addressed as follows:

1. The PSL concrete structures and concrete structural components are located in a subtropical climate with long warm summers accompanied by abundant rainfall and mild dry winters, and therefore, freeze-thaw is not an applicable aging mechanism for the concrete structures and concrete components.

2. Group 2 and 9 structures are not applicable at PSL. Group 1, 3-5, 7, and 8 structures at PSL are designed and constructed in accordance with ACI 318-63 (Unit 1) and ACI 318-71 (Unit 2) using ingredients/materials conforming to ACI and ASTM standards. The aggregates used in the concrete of the PSL concrete components did not come from a region known to yield aggregates suspected of or known to cause aggregate reactions. All aggregates used at PSL conform to the requirements of "Specification of Concrete Aggregates" ASTM-C33-67 and –71, to ensure that the hardness, weight, strength, durability, reactivity, and gradation fall within the limits established for a good grade of concrete. PSL concrete components were constructed using aggregates from approved sources whose acceptability was based on established industry standards and ASTM tests. The concrete mix uses Type II Portland cement conforming to ASTM C150. Also, for Unit 2, the cement contains no more than 0.60 percent by weight of total alkalis, which prevents harmful expansion due to alkali aggregate reaction. Materials for concrete used in PSL concrete SSCs were specifically investigated, tested, and examined in accordance

with pertinent ASTM standards at the time of construction The Structures Monitoring (B.2.3.33) 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 alkali carbonate reaction (ACR), and includes opportunistic inspection of inaccessible concrete locations. As such, a plant specific program or plant specific enhancement of the Structures Monitoring (B.2.3.33) AMP is not required to manage this aging effect; rather, inspections and evaluations performed in accordance with the Structures Monitoring (B.2.3.33) AMP will identify the presence of expansion and cracking due to reaction with aggregates should it occur.

3. PSL concrete structures are located on well compacted Class I fill and are not adversely affected by any variations of the groundwater table. Therefore, since significant changes in underground water conditions are not expected, the PSL concrete structures are not expected to experience any additional appreciable settlement over the future life of the units. Additionally, a dewatering system was used during construction to lower the water table; however, the dewatering system is not being used during the current period of operation nor is it credited in the SPEO.

4. PSL Units 1 and 2 concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed in accordance with ACI 301 using ingredients conforming to ACI and ASTM standards, which provide for a good quality, dense, low permeability concrete. The exterior walls of the PSL concrete structures are exposed to the outside environment and are expected to have rainwater passing over the exterior surface. Components of select foundations are located below groundwater elevation and thus could be susceptible to leaching of calcium hydroxide. Cracks and improperly prepared construction joints provide the easiest mechanism for entry of water and are likely areas for leaching. Leaching has been observed several times in the Unit 1 RAB ECCS Room. These structures will continue to be managed by the Structures Monitoring (B.2.3.33) AMP during the SPEO.

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 PSL licenses (3.5.2.3.2), however, local hot spots for concrete penetrations outside containment were not evaluated. Conservatively, insulation on process piping with temperatures above 200ºF is included in the scope of SLR to assist in maintaining local concrete temperatures. The aging management of this insulation is provided by the PSL External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP.

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).*

Further evaluation for Inaccessible Areas for Group 6 Structures is provided below:

Note that structures and components submerged underwater are considered accessible [NUREG-2191, Table IX.B].

1. Group 6 Structures at PSL; intake, discharge, and emergency cooling canals, ultimate heat sink (UHS) dam, and intake structures are located in a subtropical climate with long warm summers accompanied by abundant rainfall and mild dry winters, and therefore, freeze-thaw is not an

applicable aging mechanism for the concrete structures and concrete components.

2. Group 6 structures at PSL are designed and constructed in accordance with ACI 318-63 (Unit 1) and ACI 318-71 (Unit 2) using ingredients/materials conforming to ACI and ASTM standards. The aggregates used in the concrete of the PSL concrete components did not come from a region known to yield aggregates suspected of or known to cause aggregate reactions. All aggregates used at PSL conform to all the requirements of “Specification of Concrete Aggregates” ASTM-C33-67 and –71, to ensure that the hardness, weight, strength, durability, reactivity, and gradation fall within the limits established for a good grade of concrete. PSL concrete components were constructed using aggregates from approved sources whose acceptability was based on established industry standards and ASTM tests]. The concrete mix uses Type II Portland cement conforming to ASTM C150. Also, for Unit 2, the cement contains no more than 0.60 percent by weight of total alkalis, which prevents harmful expansion due to alkali aggregate reaction. Materials for concrete used in PSL concrete SSCs were specifically investigated, tested, and examined in accordance with pertinent ASTM standards at the time of construction. However, this testing may not fully conform to ASTM C295 specified in NUREG 2192, and, therefore, cracking due to expansion and reaction with aggregates, including alkali silicate reactions (ASR) and alkali carbonate reactions, is a potential aging effect in below grade inaccessible concrete areas for PSL Group 6 structures and will be managed by the PSL Structures Monitoring (B.2.3.33) AMP. The Structures Monitoring (B.2.3.33) 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 alkali carbonate reaction (ACR), and includes opportunistic inspection of inaccessible concrete locations. As such, a plant specific program or plant specific enhancement of the Structures Monitoring (B.2.3.33) AMP is not required to manage this aging effect; rather, inspections and evaluations performed in accordance with the Structures Monitoring (B.2.3.33) AMP will identify the presence of cracking due to expansion and cracking due to reaction with aggregates should it occur.

3. The exterior walls of PSL concrete structures are exposed to the outside environment and are expected to have rainwater passing over the exterior surface. Components of the intake structure, UHS dam and select foundations are exposed to saltwater or are located below groundwater elevation and thus could be susceptible to leaching of calcium hydroxide. Cracks and improperly prepared construction joints provide the easiest mechanism for entry of water and are likely areas for leaching. 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 which is characteristic of concrete having low permeability. This is consistent with the guidance provided by ACI 201.2R-77 and when implemented,

degradation caused by leaching of calcium hydroxide is not significant. In addition, concrete components are normally exposed to flowing water (not just filling a crack or void) through the concrete component.

Leaching is readily noticeable because of the white deposit that remains on the concrete surface after the carbon dioxide dries. No significant signs of leachate have been documented during inspection walkdowns under the Structures Monitoring (B.2.3.33) AMP. However, CR 01-1603 reported that minor concrete leaching is evident on the interior surface of the concrete walls at the ultimate heat sink dam. The suspected cause is rainwater passing through cracks or cold joints in the concrete. Due to the small amount of efflorescence at the location of the cracks, any degradation of the existing concrete due to precipitation of calcium carbonate and/or calcium hydroxide would be negligible. The CR concludes that the condition will not affect the structural integrity of the concrete and that no generic actions are required. For SLR, the UHS dam will be monitored in accordance with the requirements of the Structures Monitoring (B.2.3.33) AMP.

Concrete components at the intake structure, UHS dam and the concrete covered dike walls at the intake structure, are exposed to the flowing water from the intake canal. However, as discussed above, concrete used for these concrete components was designed in accordance with ACI 318 and its relevant standards and ASTM specifications to maximize resistance to leaching. Walkdowns at the intake structure and the UHS dam have not found any significant instances of leaching (except as noted above at the UHS dam). However, the below-grade inaccessible concrete areas of Groups 6 concrete structures at PSL are exposed 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 PSL Groups 6 concrete structures, thus, the PSL Structures Monitoring (B.2.3.33) AMP will manage increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation in below-grade inaccessible concrete areas of PSL Group 6 concrete structures.

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 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 stress corrosion cracking (SCC) and loss of material due to pitting and crevice corrosion is possible in SS and aluminum structural components exposed to any air, or underground environment where sufficient halides (e.g., chlorides) and moisture are present, and for tank foundations and anchor bolts where water may collect.

Stainless steel structural components are limited in comparison to the amount of stainless-steel mechanical components at the site. Aluminum in plant structures is limited to fire barrier mechanical penetrations. Furthermore, there has been no site OE of cracking or localized corrosion of SS or aluminum SSCs. However, cracking due to SCC and loss of material due to pitting and crevice corrosion is a potentially applicable aging effect at PSL plant structures for SS and aluminum, and is monitored with the PSL Structures Monitoring (B.2.3.33) AMP.

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 CLB 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 PSL requiring evaluation as TLAA. Cumulative fatigue damage due to cyclic loading is an applicable aging effect for cranes (overhead heavy and light load (related to refueling) handling systems) at PSL and is addressed in Section 4.6.

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 lightwater 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 following description applies to both PSL Units 1 and 2. The reinforced concrete primary shield wall (PSW) surrounds the reactor vessel (RV) and is anchored to the lower mass concrete at Elevation 18.0 ft. The arrangement of the reactor building internal concrete is shown in Figure 3.5.2.2-1. The internal structure consists of a 33 ft. thick section of mass concrete which rests atop the 10 ft. thick reactor building base mat. The reactor cavity extends about 21 ft. into the mass concrete section. Above the mass concrete section, a 7 ft., 3 in. thick concrete primary shield wall surrounds the reactor. This wall continues up to the operating deck and forms a part of the refueling canal wall. The reactor support beams are embedded into the primary shield wall approximately 5 ft. above the top of the mass concrete. The 7 ft. 3 in. thick PSW and the mass concrete on which it rests (elevation 7.5’ to 18’), which is identified as the lower cavity concrete (LCC), surrounds the RV where potential radiation damage in the concrete is maximum. Both the Unit 1 and Unit 2 PSW/LCC have the same configuration. There is no liner on the PSW/LCC.

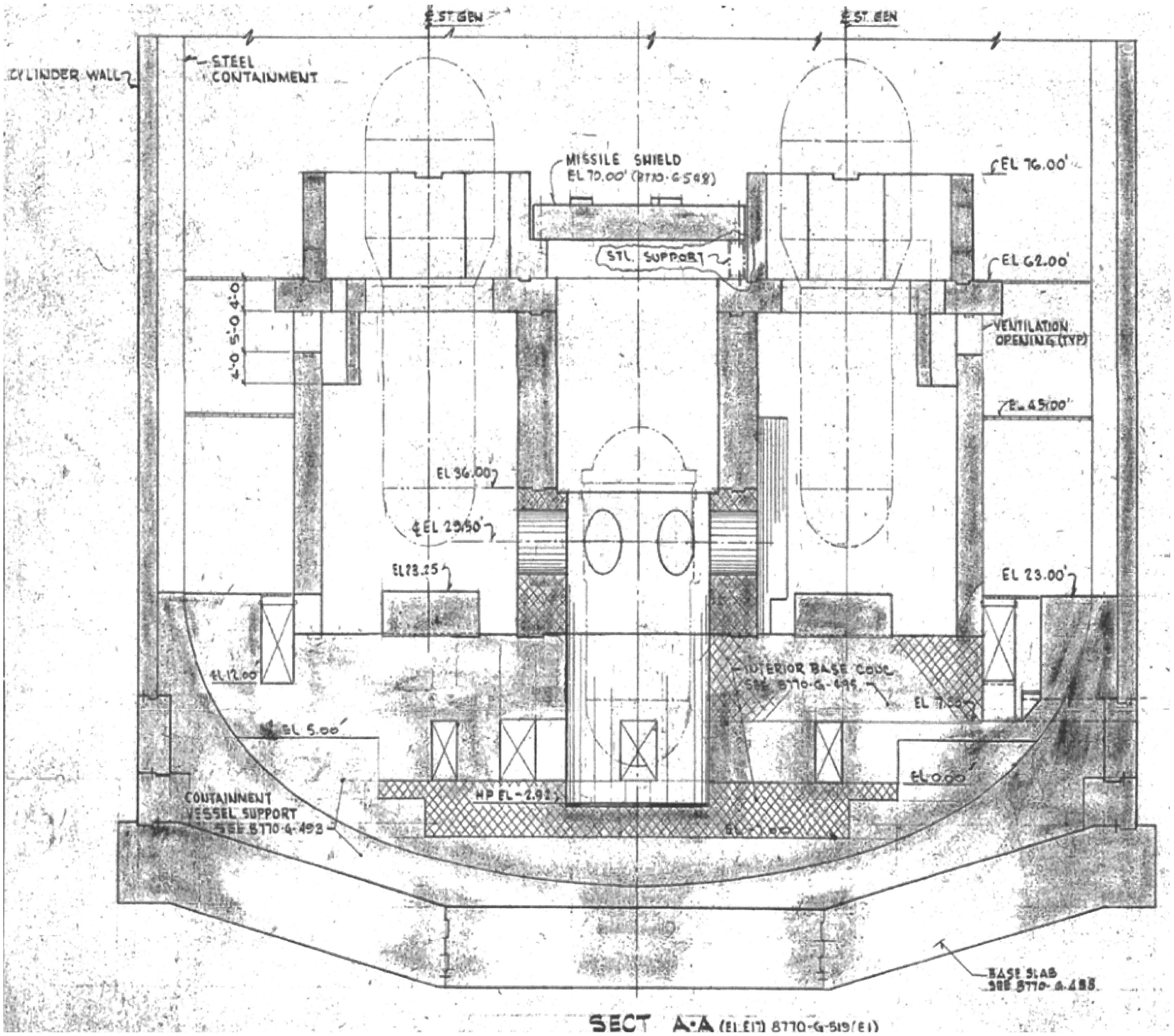


Figure 3.5.2.2-1 – Elevation View of the PSL Containment Concrete

The reactor is supported at three points on a steel girder-column assembly within the reactor cavity. Three horizontal girders are embedded in the concrete PSW, approximately 6 ft. on each end. A column is bolted to the underside of each girder mid-span and extends vertically to the reactor cavity floor. The support arrangement is shown in Figure 3.5.2.2-2.

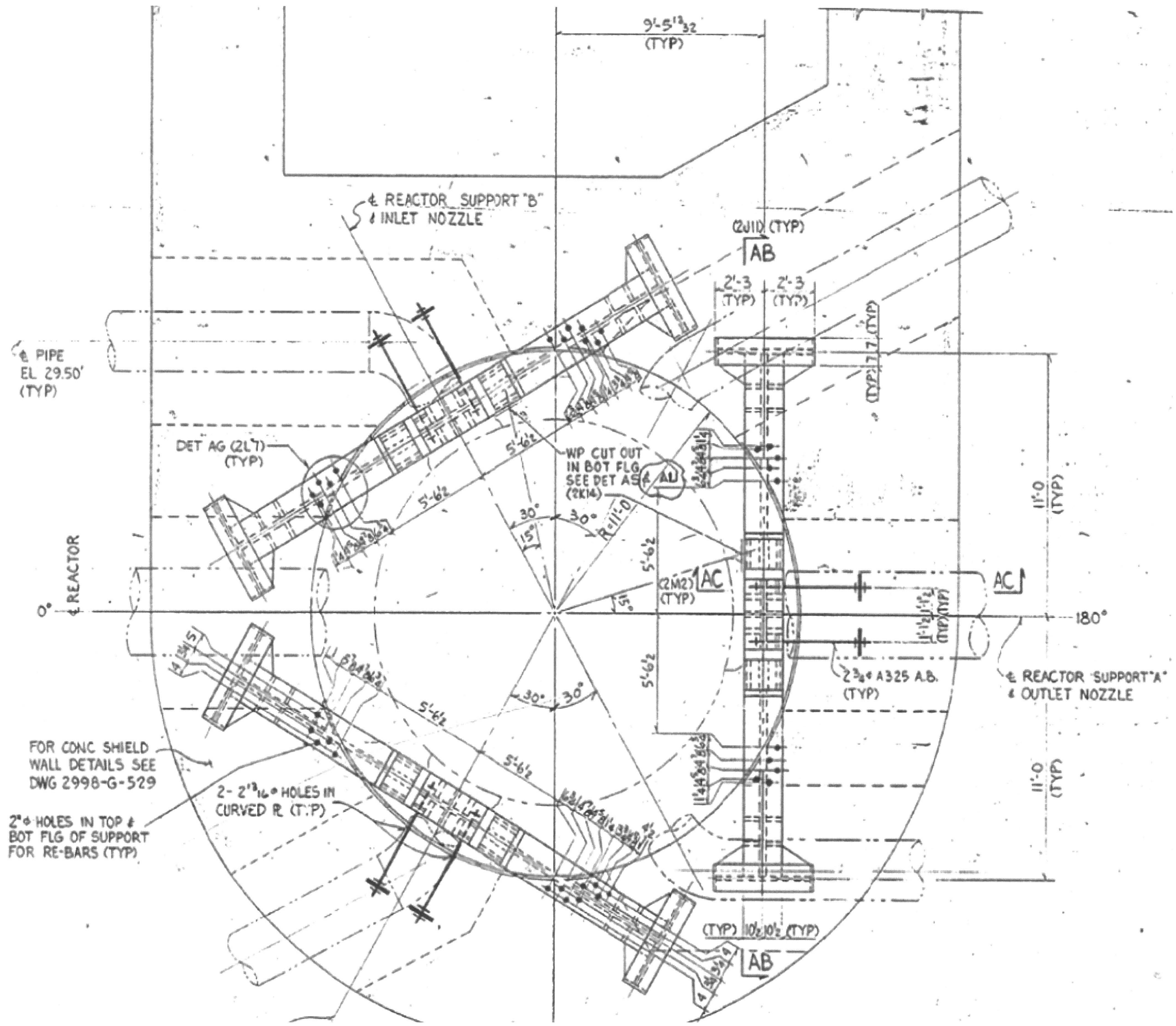


Figure 3.5.2.2-2 – Reactor Vessel Support Configuration

Load transfer between the reactor system and the reactor supports occurs between the support shoes which are welded to the reactor vessel nozzles and steel bearing plates designed into the top of the steel support girders. The support shoes are free to slide in a direction longitudinally along the axis of the nozzles and only a frictional load is transmitted to the support structure in this direction. In the transverse direction, steel plates at the top of the girders take load from the shoes in direct bearing.

Per the concrete design drawings and specifications for PSL Unit 1 and PSL Unit 2, the concrete specifications for the PSW/LCCs are as shown in Table 3.5.2.2-1:

Table 3.5.2.2-1
PSL Primary Shield Wall/ Lower Cavity Concrete Specifications

Ingredients	Applicable Specification	
	PSL Unit 1	PSL Unit 2
Strength	5000 psi	5000 psi
Cement	ASTM C-150 Type II	ASTM C-150 Type II
Air Entraining Agent	ASTM C-260	ASTM C-260
Water Reducing Agent	ASTM C-494 Type A and D	ASTM C-494 Type A and D
Aggregate	ASTM C-33 Fine aggregate consists of natural and/or manufactured sand Coarse aggregate consists of hard, durable crushed rock or natural gravel	ASTM C-33 Fine aggregate consists of natural and/or manufactured sand Coarse aggregate consists of hard, durable crushed rock or natural gravel
Water to Cement Ratio	0.44 to 0.60	0.42

The neutron transport methodology used by the Westinghouse Electric Company (Westinghouse or WEC) to generate the data provided in References 3.5.4.1 and 3.5.4.2, followed the guidance of Regulatory Guide 1.190 (Reference 1.6.15) and was consistent with the NRC approved methodology described in WCAP-18124-NP-A (Reference 3.5.4.3). This methodology has been generically approved for calculations of exposure of the RV beltline (generally, RV materials surrounding the height of active fuel). No method, generic or specific to PSL has been approved by the NRC for the other calculations performed (i.e., exposure of RV extended beltline materials, RV supports and PSW/LCC).

Westinghouse calculated the maximum neutron fluence (E > 0.1 MeV), gamma dose and displacements per iron atom (dpa) for the end of the SPEO incident on the PSW/LCC based on the reactor models and radiation transport calculations performed for the PSL SLR reactor vessel (RV) neutron exposure. These calculations were performed on a fuel-cycle-specific basis at PSL Units 1 and 2 for 72 effective full power years (EFPY). Unlike what was done for initial license renewal, future projections for PSL SLR included a 10% 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.

The 10% positive bias applied to the projection cycle peripheral and re-entrant corner assembly relative powers is intended to account for normal cycle-to-cycle variations that have been observed in past PSL core designs and are expected to occur in future ones as well. Note that, with the exception of the extended power uprate (EPU), there have been no changes to plant operating conditions, fuel design, or fuel management since the initial license renewal that have resulted in a continuous increase (or decrease) in cycle-to-cycle exposure rates.

Provided in Table 3.5.2.2-2 are the results of the neutron fluence and gamma dose calculations:

Table 3.5.2.2-2
End of Subsequent Period of Extended Operation (72 EFPY) Exposures for PSL Concrete

Component	Neutron Fluence (n/cm^2)	Gamma Dose (rads)
Unit 1 PSW/LCC	1.29×10^{19}	6.39×10^{9}
Unit 2 PSW/LCC	1.42×10^{19}	6.62×10^{9}

Based on these results, the projected end of SPEO gamma doses for PSL Unit 1 and PSL Unit 2 fall below the NUREG-2191 and NUREG-2192 concrete irradiation damage threshold for gamma radiation (1.0×10^{10} rads). Accordingly, no further evaluation of the PSL Units 1 and 2 PSW/LCCs for gamma irradiation effects is required.

Neutron fluence attenuation and radiological effects on the PSW/LCCs were determined utilizing industry guidance provided in EPRI report 3002002676 (Reference 3.5.4.4), PNNL-15870 entitled “Compendium of Material Composition Data for Radiation transport Modeling” (Reference 3.5.4.5), and EPRI Report 3002011710 (Reference 3.5.4.6).

Reference 3.5.4.6 uses attenuation ratio to determine the point into the concrete where the fluence will reach the NUREG-2192 neutron fluence damage threshold of 1×10^{19} n/cm^2. The attenuation ratio is defined as (threshold fluence)/(incident fluence at the surface of the concrete). The information in Reference 3.5.4.6 is representative of the PSL concrete in relation to 2-loop PWR fluence model, use of Portland cement, and use of sand and crushed rock aggregate. Using the higher Unit 2 value for neutron fluence calculated by Westinghouse, the attenuation ratio to reach the neutron fluence damage threshold in NUREG-2192 would be = 1/1.42 = 0.70. Using the formula for the attenuation curve (Reference 3.5.4.6), neutron fluence would reach the damage threshold at 0.8 in. into the PSW/LCC. Based on this fluence and using a realistic concrete strain at ultimate strength from ACI 318-69 of 0.003, the radiation-induced volumetric expansion depth is 0.

The governing failure mode is the tensile failure of the vertical rebars at the inner face of the PSW/LCC. Based on the irradiation effects summarized above, and the original analysis of the PSW/LCC under CLB loading conditions for both PSL Units 1 and 2, there will be minimal effect on the IR associated with the governing failure mode of 0.77. Note that this IR is based on a guillotine break of the main primary loop piping, thus the actual IR will be much lower considering both PSL Units 1 and 2 have implemented leak-before-break of the primary loop piping as part of their CLBs.

Conservatisms in the above evaluation were as follows:

- Exposures were based on 72 EFPY which is more than best estimate EFPY based on a 95% capacity factor of ~69 EFPY.
- Future projections included a 10% 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 PSW/LCC 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.

Therefore, the PSW/LCCs for PSL Units 1 and 2 will continue to be able to perform their intended functions consistent with the CLBs of both PSL Units 1 and 2 when the long-term radiation effects through the SPEO, and a plant specific AMP or an enhancement to an existing AMP is not required. Although the PSL PSW/LCCs do not have a liner plate on their outside surfaces, localized cracking and spalling of the concrete at the peak areas of neutron fluence due to radiation-induced volumetric expansion are not expected. The reactor cavity areas for both units will continue to be inspected as part of the Structures Monitoring AMP (Section B.2.3.33).

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 rated assemblies or cranes located inside containment.

PSL will continue to follow the on-going industry efforts that are clarifying the effects of irradiation on shield wall concrete and corresponding aging management recommendations (see commitments 49 in Tables 19-3 of Appendices A1 and A2).

3.5.2.2.2.7. Expected Further Evaluation for Loss of Fracture Toughness due to Irradiation Embrittlement of Reactor Pressure Vessel (RPV) Supports from NRC Review of the Previous 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).*

Geometry of Supports

The PSL RPV support structure consists of three long steel columns (ASTM A-441) extending about 23 feet downward to the interior concrete structure below the RPV. The three columns of the support structure are bolted (ASTM A-325) at the top to a horizontal support made of ASTM A-441 and ASTM A-533 Class 2 Grade B stiffener plates. A support foot is welded to the underside of the RPV nozzle, which bears on the socket/slide assembly and is fastened to the support structure between the two blocks on top of the horizontal support. Lubrication is applied to both sides of the slide plate to permit radial expansion and contraction of the vessel and lateral movement atop the RPV supports. The three columns support three reactor vessel nozzles; one column support braces under a hot leg nozzle, while the two other columns are supporting two cold leg nozzles on the loop opposite of the hot leg nozzle support. The RPV supports are shown in Figure 3.5.2.2-3 and Figure 3.5.2.2-4.

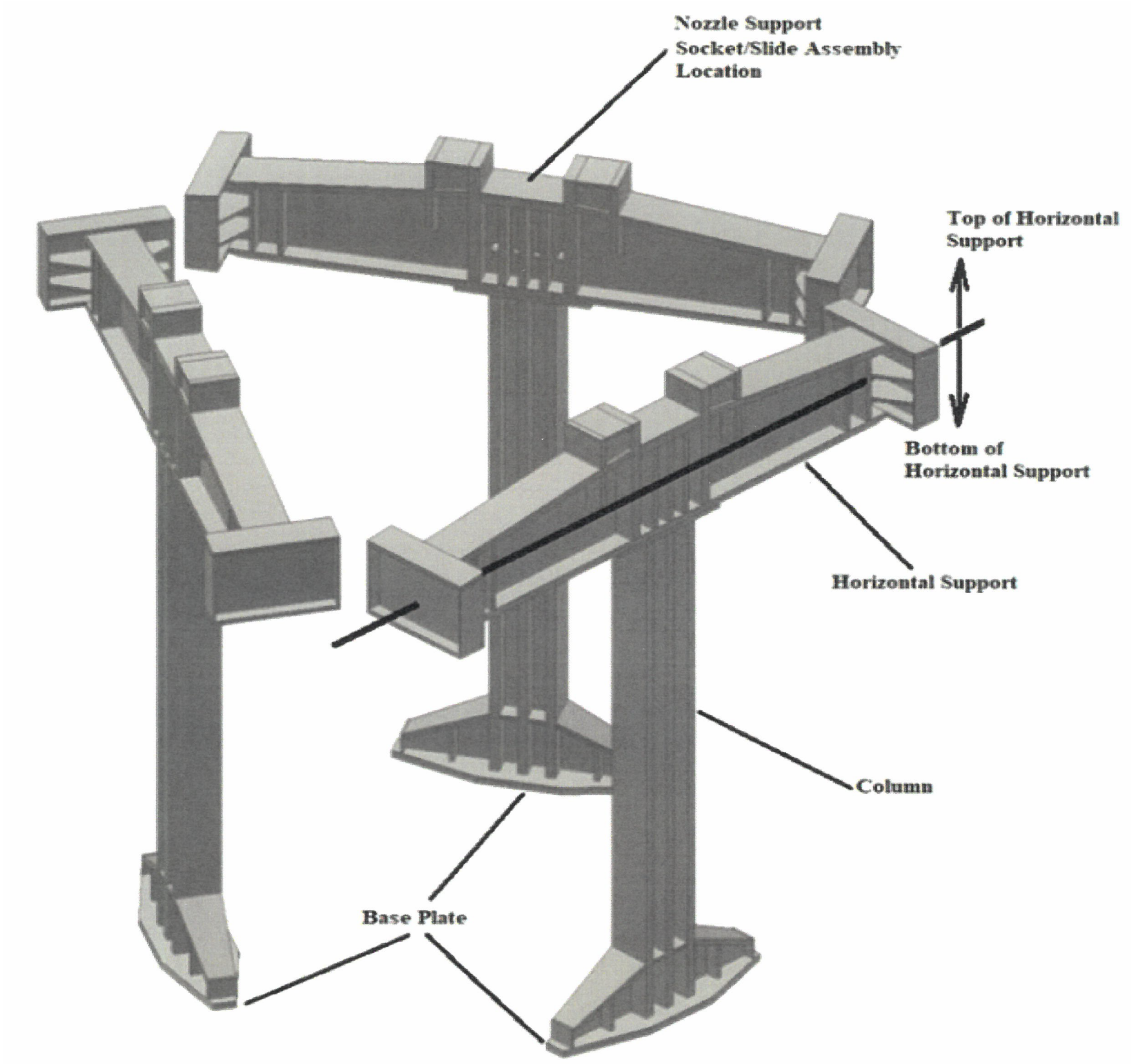


Figure 3.5.2.2-3 PSL Reactor Pressure Vessel Supports Design

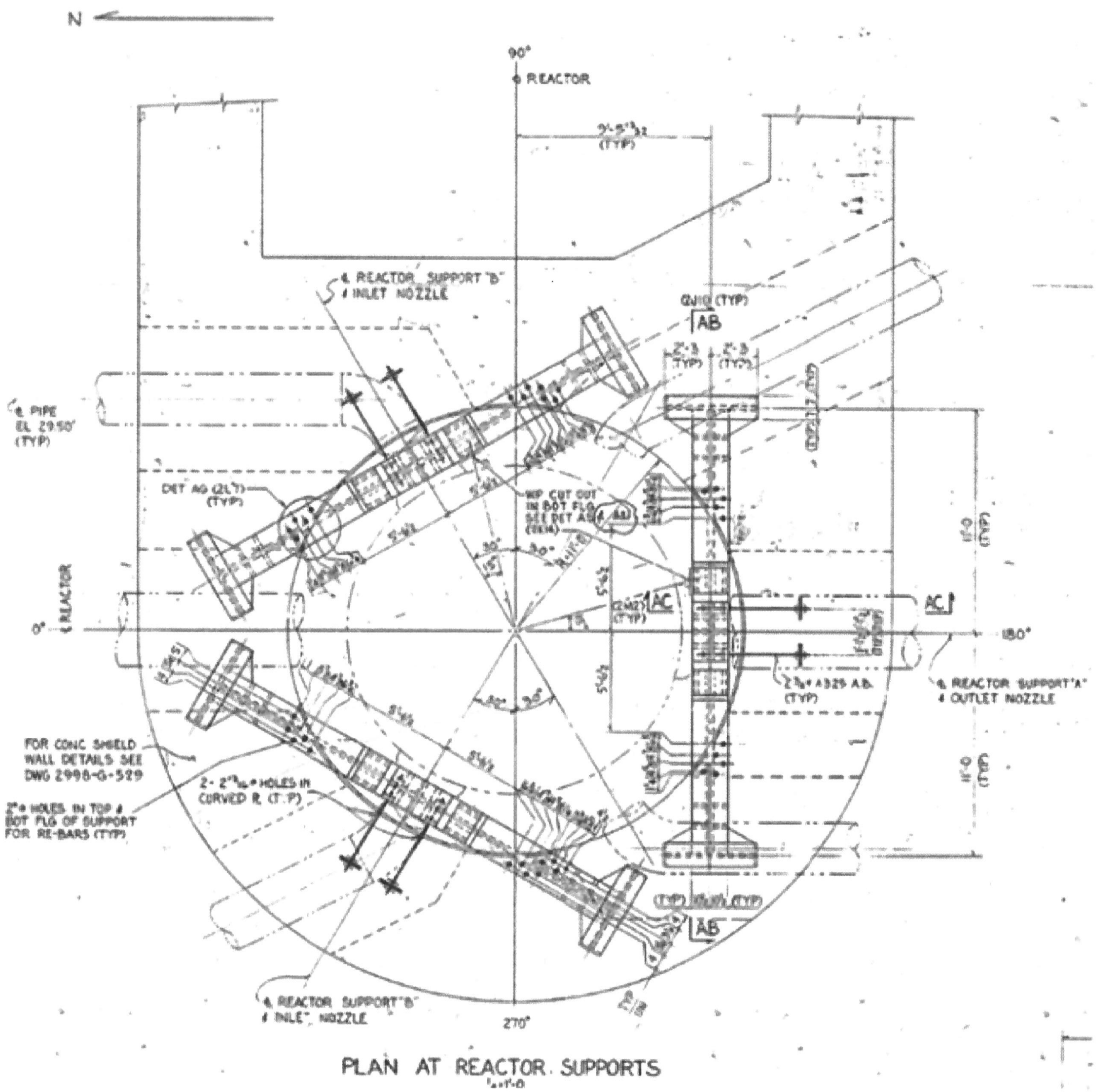


Figure 3.5.2.2-4 Plan View of Reactor Pressure Vessel Supports

<u>Method</u>

The NRC previously identified radiation embrittlement of the RPV supports as a generic safety issue (GSI-15, Reference 1.6.16). The NRC resolved the issue, as documented in NUREG-1509 (Reference 1.6.17) 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 RPV 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 PSL reactor vessel support steel was performed for the SLR.

Westinghouse performed a qualitative assessment of the PSL Units 1 and 2 structural steel RPV supports in References 3.5.4.7 and 3.5.4.8. A comparison of the key inputs to ASME Section XI critical flaw size calculations was made between PSL and Point Beach Nuclear (PBN) in order to ascertain the acceptability of the PSL RPV Supports for the subsequent period of extended operation (SPEO) with consideration of irradiation aging effects. These key inputs consist of the fracture toughness and stresses of the RPV support components and were combined into a comparative ratio term based on the general form of stress intensity factor. This comparative ratio effectively normalizes the fracture toughness and stress relative to PBN as it pertains to the calculation of critical flaw sizes. A normalized ratio greater than 1 indicates the PSL critical flaw size would be larger than that of PBN and therefore, the conclusions contained within the detailed PBN fracture mechanics evaluation (References 3.5.4.9 and ML21111A155) can be applied to PSL.

The plant-specific PSL component fracture toughness for 72 EFPY was calculated and compared to the analogous PBN components. The methodology for fracture toughness determination for PSL is consistent with the PBN evaluation in WCAP-18554-P. PSL unit specific fluence values are taken into consideration for the embrittlement using the upper bound curve from Figure 3-1 of NUREG-1509. Available material specific Charpy V-notch (CVN) test results from certified material test reports (CMTR) are considered for the fracture toughness determination. NUREG-1509 guidance is used for fracture toughness determination where CVN data is not available.

As noted in Section 3.5.2.2.2.6, neutron fluence calculations were performed by Westinghouse to determine exposures to the RPV 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 RPV beltline (generally, RPV materials opposite the active fuel). No method, generic or specific to PSL has been approved by the NRC for the other calculations performed (i.e., exposure of RPV extended beltline materials, RPV supports, Biological Shield Wall (BSW) and PSW concrete).

Westinghouse calculated the maximum neutron fluence (displacements per iron atom (dpa) and neutrons per square centimeter, $E > 0.1$ MeV) for the end of the SPEO on the RPV support components, based on the reactor models and radiation transport calculations performed for the PSL SLR RPV neutron exposure. These calculations were performed on a fuel-cycle-specific basis at PSL 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 cycles. 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. See References 3.5.4.1 and 3.5.4.2 for dpa and fluence calculations, a summary is included in Table 3.5.2.2-3 and Table 3.5.2.2-4. Note that the qualitative comparison with PBN conservatively applied the calculated plant specific full energy spectrum dpa values to evaluate embrittlement impact on toughness. The n/cm^2 fluence listed in Table 3.5.2.2-3 and Table 3.5.2.2-4 is based on the greater than 0.1 MeV energies so that a direct comparison can be made to PBN.

Table 3.5.2.2-3
Fluence for Unit 1 Reactor Pressure Vessel Supports

Component	Displacements per Iron Atom (dpa) (Full Energy) at 72 EFPY	Fluence n/cm^2 (E > 0.1 MeV) at 72 EFPY
Support Column – maximum	1.06E-02	3.27E+19
Top of 6” plate under nozzle foot	1.61E-03	5.39E+18
Bottom of horizontal support (top of column) (56” below top of 6” plate)	1.06E-02	3.27E+19
~10 feet higher in elevation than Support Column bottom	3.17E-04	1.05E+18

Table 3.5.2.2-4
Fluence for Unit 2 Reactor Pressure Vessel Supports

Component	Displacements per Iron Atom (dpa) (Full Energy) at 72 EFPY	Fluence n/cm^2 (E > 0.1 MeV) at 72 EFPY
Support Column – maximum	1.10E-02	3.34E+19
Top of 6” plate under nozzle foot	1.35E-03	4.56E+18
Bottom of horizontal support (top of column) (56” below top of 6” plate)	1.10E-02	3.34E+19
~10 feet higher in elevation than Support Column bottom	4.28E-04	1.42E+18

Westinghouse assessed the RPV slide plate lubricant for degraded conditions such as a decrease in viscosity due to radiation effects. Neutron flux was identified as the key parameter in irradiation aging effects of dry film lubricants such as that employed at PSL. The average flux at the RPV slide plate for 72 EFPY was calculated and shown to be below the threshold where degradation is observed. Therefore, the functionality of the lubricant is not adversely affected by the radiation exposure in the SPEO.

The faulted conditions were determined as the limiting condition per WCAP-18554-P. The stress is calculated from the total cumulative load of the deadweight, thermal, safe shutdown earthquake (SSE), and loss of coolant accident (LOCA). This coincides with UFSAR Subsection 3.7.3.3.2 which lists the faulted condition as the loads resulting from normal operation, design basis earthquake (DBE) and postulated LOCA. The loads for the deadweight, thermal, and SSE were taken from the current analysis of record. The LOCA stresses were calculated accounting for leak-before-break on the RCS hot and cold leg which have been accepted as part of the licensing basis per UFSAR 3.6.3.1. Additionally, weld residual stress is considered for the evaluation of welds and the heat affected zones of the base metal for the RPV supports.

Operating Experience

Section 4.3.1.1 of NUREG-1509 states that physical examination of the RPV 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 PSL RPV supports as part of the current PSL ASME Section XI, Subsection IWF Inservice Inspection Program consist of VT-3 visual inspections and magnetic particle examination (MT) of the nozzle support. These inspections are summarized below with the specifics provided on the portal:

Unit 1

VT-3 inspections of accessible portions of the Unit 1 PSL cold leg RPV supports were performed in 2021. The VT-3 inspection of the RPV hot leg support was performed in 2018. Both inspections indicated acceptable results meeting the acceptance criteria of IWF-3410 and did not identify any areas requiring further evaluation.

Unit 2

VT-3 inspections of accessible portions of the Unit 2 PSL cold leg RPV supports were performed in 2012. These inspections were performed on all accessible areas to the extent possible. The VT-3 inspection data sheet from the 2012 inspection indicated acceptable results meeting the acceptance criteria of IWF-3410 and did not identify any areas requiring further evaluation.

Table 3.5.2.2-5
Normalized Ratio Comparison for Most Limiting Faulted Load

	PSL Unit 1		PSL Unit 2	
Plate Material	**A-441**	**A-533 Cl. 2 Gr. B**	**A-441**	**A-533 Cl.2 Gr. B**
Top Horizontal Support Plate	4.34	2.56	7.09	7.30
Bottom Horizontal Support Plate	4.07	2.52	4.31	2.58

Summary of Results

The comparative ratios calculated for the PSL RPV supports are greater than one indicating that the projected critical flaw sizes for the PSL supports would be greater than those for PBN. See Table 3.5.2.2-5 for a comparative ratio of the most limiting regions for the most limiting branch line pipe break (BLPB) as concluded in LTR-SDA-21-021-P (Reference 3.5.4.8). Additionally, OE shows that VT-3 inspections were performed in accordance with ASME Section XI, and results have met the acceptance criteria of Subsection IWF-3410. Therefore, the conclusions in WCAP-18554 can be conservatively applied to PSL. Based on the discussions above the RPV supports at PSL 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 examinations (VT-3) of the RPV structural steel supports as part of the PSL ASME Section XI, Subsection IWF Inservice Inspection Program. 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 RPV supports at PSL.

3.5.2.3 Time-Limited Aging Analysis

The TLAAs identified below are associated with the Containments, Structures and Component Support 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 Conclusion

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 Report LTR-REA-21-1-NP, Revision 1, St. Lucie Units 1 & 2 Subsequent License Renewal: Unit 1 Reactor Vessel, Vessel Support, and Bioshield Concrete Exposure Data, May 26, 2021 (Enclosure 4, Attachment 1).

3.5.4.2 Westinghouse Report LTR-REA-21-2-NP, Revision 1, St. Lucie Units 1 & 2 Subsequent License Renewal: Unit 2 Reactor Vessel, Vessel Support, and Bioshield Concrete Exposure Data, June 7, 2021 (Enclosure 4, Attachment 2).

3.5.4.3 Westinghouse Report WCAP-18124-NP-A, Revision 0, "Fluence Determination with RAPTOR-M3G and FERRET," July 2018. ADAMS Accession No. ML18204A010.

3.5.4.4 EPRI Report No. 3002002676, "Expected Condition of Reactor Cavity Concrete After 80-Years of Radiation Exposure", Electric Power Research Institute, Charlotte, NC, March 2014.

3.5.4.5 PNNL 15870, Revision 1 "Compendium of Material Composition Date for Radiation Transport Modelling", April 2006.

3.5.4.6 EPRI Report No. 3002011710, "Irradiation Damage of the Concrete Biological Shield Wall for Aging Management", EPRI, Palo Alto, CA, May 2018.

3.5.4.7 Westinghouse Report LTR-SDA-21-021-NP, Revision 1, St. Lucie Units 1&2 Subsequent License Renewal: Reactor Pressure Vessel Supports Assessment, June 24, 2021 (Enclosure 4, Attachment 3).

3.5.4.8 Westinghouse Report LTR-SDA-21-021-P, Revision 1, St. Lucie Units 1&2 Subsequent License Renewal: Reactor Pressure Vessel Supports Assessment, June 24, 2021 (Enclosure 5, Attachment 1).

3.5.4.9 Enclosure 4, Attachment 2 and Enclosure 5, Attachment 2 to NextEra Energy Point Beach, LLC (NEPB) Letter NRC 2020-0032 dated November 16, 2020, Application for Subsequent Renewed Facility Operating Licenses (ADAMS Package Accession No. ML20329A292), 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.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.5-1, 001	Concrete: dome; wall; base mat; 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)	Not applicable PSL does not rely on a permanent de-watering system to control settlement. However, the Structures Monitoring (B.2.3.33) AMP 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. PSL 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.
3.5-1, 003	Concrete: dome; wall; base mat; ring girders; buttresses, concrete: containment; wall; base mat, concrete: base mat, 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 applicable. 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. Hot (Type I) penetration assemblies include insulation. This insulation has an 'insulate (thermal)' function for SLR and is addressed in Table 3.5.2-1. Further evaluation is documented in Section 3.5.2.2.1.2.
3.5-1, 004	This line item only applies to BWRs.				

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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 containment vessel and attachments are managed by the ASME Section XI, Subsection IWE (B.2.3.29) AMP and 10 CFR Part 50, Appendix J (B.2.3.31) AMP. Further evaluation is documented in Section 3.5.2.2.1.3.
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)	Not applicable. PSL shield building is a reinforced concrete structure. It does not include prestressed tendons. Concrete tendon prestress TLAA is not applicable. Further evaluation is documented in Section 3.5.2.2.1.4.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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 containment vessel, containment vessel nozzle and mechanical penetration assemblies and fuel transfer tube assemblies. 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 due to SCC of high and moderate temperature mechanical penetration assemblies that are stainless steel or include dissimilar metal welds is addressed for item number 3.5-1, 010.
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.2.3.31) AMP manage cracking of Type III (semi-hot) 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; base mat; 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)	Not applicable. PSL is located in a subtropical climate with long warm summers accompanied by mild, dry winters with negligible freeze-thaw cycles. Further evaluation is documented in Section 3.5.2.2.1.7.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.5-1, 012	Concrete (inaccessible areas): dome; wall; base mat; 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)	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.33) 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; base mat; 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 Section 3.5.2.2.1.9)	Consistent with NUREG-2191. The PSL Shield Building is susceptible to water-flowing due to exposure to groundwater. The Structures Monitoring (B.2.3.33) AMP includes opportunistic inspection of inaccessible areas and would identify leaching or carbonation of Shield Building base mat exposed to groundwater (water-flowing). Further evaluation is documented in Section 3.5.2.2.1.9.
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	Not applicable. PSL does not have a reinforced concrete containment. The Structures Monitoring (B.2.3.33) AMP manages increase in porosity and permeability, cracking, and loss of material (spalling, scaling) for accessible Shield Building concrete as addressed for item number 3.5-1, 067
3.5-1, 017	Item number 3.5-1, 017 is deleted in NUREG-2192				
3.5-1, 018	Concrete (accessible areas): dome; wall; base mat; 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	Not applicable. PSL is located in a subtropical climate with long, warm summers accompanied by abundant rainfall and mild, dry winters with negligible freeze-thaw cycles.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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	Not applicable. PSL does not have a reinforced concrete containment. The Structures Monitoring (B.2.3.33) AMP manages cracking of accessible Shield Building concrete exposed to an outdoor environment as addressed for item 3.5-1, 054.
3.5-1, 020	Concrete (accessible areas): dome; wall; base mat; 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. There are no portions of the Containment Vessel or accessible areas of the Shield Building concrete that are exposed to flowing water.
3.5-1, 021	Concrete (accessible areas): dome; wall; base mat; 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 Structures Monitoring (B.2.3.33) AMP manages cracking, loss of bond, and loss of material (spalling, scaling) for accessible containment concrete exposed to outdoor air environment.
3.5-1, 022	Item number 3.5-1, 022 is deleted in NUREG-2192.				
3.5-1, 023	Concrete (inaccessible areas): base mat; 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 Structures Monitoring (B.2.3.33) AMP manages cracking, loss of bond, and loss of material (spalling, scaling) for inaccessible Shield Building concrete exposed to uncontrolled indoor air.
3.5-1, 024	Concrete (inaccessible areas): dome; wall; base mat; ring girders; buttresses, concrete (accessible areas): dome; wall; base mat	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 Structures Monitoring (B.2.3.33) AMP manage increase in porosity and permeability, cracking, and loss of material (spalling, scaling) in inaccessible Shield Building concrete areas exposed to groundwater/soil.
3.5-1, 025	Item number 3.5-1, 025 is deleted in NUREG-2192.				

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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 containment vessel 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"	Yes (SRP-SLR Section 3.5.2.2.1.5)	Consistent with NUREG-2191. A fatigue analysis was not performed for the Containment Vessel and a fatigue 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.2.3.31) AMP manage cyclic loading of air lock, hatch, and electrical penetration assemblies and accessories, exposed to uncontrolled indoor air. Further evaluation is documented in Section 3.5.2.2.1.5. Mechanical penetration assemblies, including piping, ventilation and fuel transfer tube, are addressed with item numbers 3.5-1, 009 and 3.5-1, 010 above.
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.2.3.31) AMP manage loss of material of the steel maintenance hatch, construction hatch and cover, air locks and accessories; and steel or nickel alloy penetration 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.2.3.31) AMP manage loss of leak tightness due to mechanical wear of airlock and maintenance hatch accessories exposed to uncontrolled indoor air

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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.2.3.31) AMP manage loss of preload due to self-loosening of the containment vessel and penetration 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 the containment vessel and penetration pressure retaining bolting exposed to uncontrolled indoor air.
3.5-1, 032	Prestressing system: tendons; anchorage components	Loss of material due to corrosion	AMP XI.S6, "Structures Monitoring"	No	Not applicable. PSL Shield Building is a reinforced concrete structure. It does not include prestressed tendons. Loss of material of steel tendons and anchorage components associated with post tensioning systems are not applicable
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.2.3.31) AMP manages loss of sealing of seals associated with the containment vessel, hatch, airlock and penetration 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.2.3.35) AMP manages loss of coating integrity of the Service Level 1 coatings inside Containment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	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.2.3.31) AMP manage loss of material of accessible areas of the steel Containment Vessel steel or dissimilar metal weld and penetration components exposed to uncontrolled indoor air. Further evaluation is documented in Section 3.5.2.2.1.3.
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.				
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 AMP 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 PSL. Structures at PSL are not exposed to freezing temperatures for sufficient durations to cause freeze-thaw aging effects. Further evaluation is documented in Section 3.5.2.2.2.1 Item 1.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	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 AMP 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 PSL. Consistent with the current renewed licenses, a plant-specific AMP is not required to manage cracking in inaccessible areas due to reaction with aggregates. PSL concrete components did not come from a region known to yield suspected of or known to cause aggregate reactions. The Structures Monitoring AMP includes examination for cracking, darkened crack edges, water ingress and misalignment that would be indicative of reaction with aggregates. The Structures Monitoring 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 PSL. PSL does not rely upon a de-watering system to control groundwater level and settlement is included in the Structures Monitoring (B.2.3.33) 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.				
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)	Group 2 and 9 structures are not applicable to St Lucie. As described for item 3.5-1, 044, PSL 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.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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 AMP 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 PSL. Consistent with the current renewed licenses, a plant-specific AMP is not required for inaccessible area. For SLR, groundwater is considered to be flowing water where leaching or carbonation could potentially occur. The Structures Monitoring (B.2.3.33) 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 area. Further evaluation is documented in Section 3.5.2.2.2.1, item 4.
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 AMP or AMP XI.S6, "Structures Monitoring" enhanced as necessary	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 St Lucie. There have been no instances of elevated temperatures for PSL 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 concrete temperatures and is managed by the External Surfaces Monitoring of Mechanical Components AMP. Further evaluation is documented in Section 3.5.2.2.2.2.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	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 AMP or AMP XI.S6, "Structures Monitoring" enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.1)	Not Applicable. Structures at PSL are not exposed to freezing temperatures for sufficient durations to cause freeze-thaw aging effects.
3.5-1, 050	Groups 6: concrete (inaccessible areas): all	Cracking due to expansion from reaction with aggregates	Plant-specific AMP 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 PSL Intake Structures, Intake, Discharge, and Emergency Cooling Canals, and Ultimate Heat Sink Dam (Barrier Wall) The Structures Monitoring (B.2.3.33) AMP (which includes opportunistic inspection of inaccessible concrete when excavated for other reasons and frequent dewatering of the intake structure bays) is credited with managing cracking in inaccessible areas of PSL structures, including the Intake Structures; Intake, Discharge, and Emergency Cooling Canals; and Ultimate Heat Sink Dam (Barrier Wall). Further evaluation is documented in Section 3.5.2.2.2.3, Item 2.
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 AMP 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 PSL Intake Structures; Intake, Discharge, Emergency Cooling Canals; and Ultimate Heat Sink Dam (Barrier Wall). The Structures Monitoring (B.2.3.33) AMP is credited with managing the inaccessible areas of plant structures including the Intake Structures; Intake, Discharge, Emergency Cooling Canals; and Ultimate Heat Sink Dam (Barrier Wall). Further evaluation is documented in Section 3.5.2.2.2.3, Item 3.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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 AMP	Yes (SRP-SLR Section 3.5.2.2.2.4)	Not applicable. PSL tanks are addressed with the mechanical system to which they belong. Furthermore, the External Surfaces Monitoring of Mechanical Components 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.
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 3.5.2-18. 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. Group 2 and 9 structures are not applicable to PSL. PSL concrete components did not come from a region known to yield suspected of or known to cause aggregate reactions. The Structures Monitoring (B.2.3.33) AMP includes examination for cracking, darkened crack edges, water ingress and misalignment that would be indicative of reaction with aggregates. The Structures Monitoring (B.2.3.33) AMP is credited with managing cracking of accessible concrete exposed to uncontrolled indoor air, and outdoor air environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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.2.3.33) AMP is credited with managing reduction in concrete anchor capacity for accessible concrete exposed to uncontrolled indoor air, and outdoor air environments.
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	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34) 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. The ASME Section XI, Subsection IWF (B.2.3.30) AMP is credited with managing loss of mechanical function for constant and variable load supports exposed to an uncontrolled indoor air environment, as described in Table 3.5.2-16.
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	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34) AMP is credited with managing Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage.
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	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34) AMP is credited with managing cracking, loss of bond, and loss of material (spalling, scaling).

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	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	None	No	Not Applicable Structures at PSL are not exposed to freezing temperatures for sufficient durations to cause freeze-thaw aging effects.
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	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34) AMP is credited with managing an increase in porosity and permeability and loss of strength for accessible concrete exposed to outdoor air, and water-flowing or standing.
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	No	Not applicable There are no wooden piles or sheeting used in the PSL Intake Structures, Intake, Discharge, and Emergency Cooling Canals, or the Ultimate Heat Sink Dam (Barrier Wall).
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.2.3.33) 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	Not Applicable. Structures at PSL are not exposed to freezing temperatures for sufficient durations to cause freeze-thaw aging effects.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	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.2.3.33) 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.2.3.33) 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.2.3.33) 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: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	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. The ASME Section XI, Subsection IWF 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.2.3.33) 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.2.3.32) 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	Not Applicable. Structures at PSL are not exposed to freezing temperatures for sufficient durations to cause freeze-thaw aging effects.
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.2.3.33) AMP is credited with managing loss of sealing for seals and weatherproofing in the Fuel Handling Buildings, Intake Structures, Reactor Auxiliary Buildings, Switchyard, and Turbine Building.
3.5-1, 073	Service Level 1 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.2.3.35) AMP manages loss of coating integrity of the Service Level 1 coatings inside Containment
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. Sliding support surfaces outside containment (CCW HX) are managed under the ASME Section XI Subsection IWF (B.2.3.30) AMP. Applicable components are addressed under item 3.5-1, 075.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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 Sliding support surface inside containment and outside containment from the CCW heat exchangers are managed under the ASME Section XI Subsection IWF (B.2.3.30) AMP.
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.2.3.33) AMP is credited with managing loss of material of structural steel components exposed to uncontrolled indoor air and outdoor air.
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. 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 components of the fuel upender) and fuel handling tools for Unit 2 exposed to treated borated water. Spent fuel pool storage racks, and fuel transfer tubes and expansion bellows are additional stainless steel components in treated water subject to SCC.
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.2.3.33) AMP is credited with managing loss of material of steel piles for the Ultimate Heat Sink Dam (Barrier Wall) and discharge nose wave protection (Yard Structures).
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.2.3.33) AMP is credited with managing loss of material for structural bolting exposed to uncontrolled indoor air and outdoor air.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.5-1, 081	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	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, 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.2.3.33) AMP is credited with managing loss of material for structural bolting exposed to outdoor air.
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	No	Not used Structural bolting exposed to uncontrolled indoor air and outdoor air is addressed under item 3.5-1, 080.
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	Not used PSL has no Class 1, 2, or 3 structural bolting in a treated borated water environment.
3.5-1, 086	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF (B.2.3.30) AMP is credited with managing loss of material for bolted connections for ASME Class 1, 2 and 3 component supports.
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. The ASME Section XI, Subsection IWF (B.2.3.30) 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.2.3.33) AMP is credited with managing loss of preload for structural bolting.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	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, crane/lifting components, and support anchorage in the Containment, Reactor Auxiliary, and Fuel Handling Buildings 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. PSL has no Class 1, 2, or 3 structural bolting in a treated borated water environment.
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. The ASME Section XI, Subsection IWF (B.2.3.30) AMP is credited with managing loss of material for ASME Class 1, 2 and 3 support members, welds, bolted connections, and support anchorage.
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.2.3.33) 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.2.3.33) AMP is credited with managing loss of material of galvanized steel supports in an outdoor air environment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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	Not Applicable. There are no vibration isolation elements requiring aging management at PSL.
3.5-1, 095	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	None	None	No	Consistent with NUREG 2191 Galvanized steel in components and commodities in an indoor air environment have no aging effect/mechanism and therefore do not require aging management.
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" or the FERC/US Army Corp of Engineers	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34) AMP is credited with managing cracking for accessible concrete in the Intake Structures; Intake, Discharge, and Emergency Cooling Canals; and the Ultimate Heat Sink Dam (Barrier Wall) .

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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 AMP or plant-specific enhancements to selected AMPs	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 and reactor vessel supports have been evaluated for end of plant life/license (the subsequent period of extended operation). The primary shield wall will continue to satisfy the design criteria considering the long-term radiation effects. The Structures Monitoring (B.2.3.33) AMP will continue to manage the primary shield wall condition. The RV supports will continue to satisfy the design criteria considering the long-term radiation effects and loss of fracture toughness will be managed by the ASME Section XI, Subsection IWF (B.2.3.30) AMP. Further evaluation is described in Sections 3.5.2.2.2.6 and 3.5.2.2.2.7.
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. PSL does not have any aluminum or stainless steel Class 1, 2, or 3 supports.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Program / TLAA	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.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)	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 aluminum and stainless steel nonsafety-related supports at the Intake Structures. The Structures Monitoring (B.2.3.33) AMP is credited with managing loss of material and cracking of stainless steel component support, anchorage embedment, electrical and instrument panel and enclosures, conduits and cable trays, and aluminum supports exposed to air. The Fire Protection (B.2.3.16) AMP is credited with managing loss of material in stainless steel fire barrier penetrations and radiant energy shields. Further evaluation is documented in Section 3.5.2.2.2.4.

Table 3.5.2-1: Containment Building 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
Air locks and maintenance hatch: seals and gaskets	Pressure boundary	Elastomer	Air – indoor uncontrolled	Loss of sealing	10 CFR Part 50, Appendix J (B.2.3.31)	II.A3.CP-41	3.5-1, 033	A
Air locks, maintenance hatch and accessories	Fire barrier Pressure boundary	Steel	Air – outdoor	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A, 1
Air locks, maintenance hatch and accessories	Fire barrier Pressure boundary	Steel	Air – outdoor	Loss of leak tightness	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-39	3.5-1, 029	A
Air locks, maintenance hatch and accessories	Fire barrier Pressure boundary	Steel	Air – outdoor	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.C-16	3.5-1, 028	A
Air locks, maintenance hatch and accessories	Fire barrier Pressure boundary	Steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A, 1
Air locks, maintenance hatch and accessories	Fire barrier Pressure boundary	Steel	Air – indoor uncontrolled	Loss of leak tightness	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-39	3.5-1, 029	A
Air locks, maintenance hatch and accessories	Fire barrier Pressure boundary	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.C-16	3.5-1, 028	A
Air locks, maintenance hatch 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

Table 3.5.2-1: Containment Building 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**
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B5.TP-25	3.5-1, 089	C
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B5.TP-3	3.5-1, 089	C
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	C
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Construction hatch and cover	Fire barrier Pressure boundary	Steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A, 1
Construction hatch and cover	Fire barrier Pressure boundary	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.C-16	3.5-1, 028	A
Construction hatch and cover	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
Containment vessel	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

Table 3.5.2-1: Containment Building 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
Containment vessel (accessible)	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A, 2
Containment vessel (accessible)	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A2.CP-35	3.5-1, 035	A, 2
Containment vessel (inaccessible)	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A2.CP-98	3.5-1, 005	A
Containment vessel 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
Containment vessel nozzle (electrical)	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A, 1
Containment vessel nozzle (electrical)	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.C-16	3.5-1, 028	A
Containment vessel nozzle (electrical)	Fire barrier 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

Table 3.5.2-1: Containment Building 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
Containment vessel nozzle (fuel transfer)	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.C-16	3.5-1, 028	A
Containment vessel nozzle (fuel transfer)	Fire barrier 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
Containment vessel nozzle (fuel transfer)	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, "Containment Penetrations Fatigue"	II.A3.C-13	3.5-1, 009	A
Containment vessel nozzle (mechanical)	Fire barrier Pressure boundary Structural support	Nickel alloy	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.C-16	3.5-1, 028	A
Containment vessel nozzle (mechanical)	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.C-16	3.5-1, 028	A
Containment vessel nozzle (mechanical)	Fire barrier 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
Containment vessel nozzle (mechanical)	Fire barrier Pressure boundary Structural support	Nickel alloy	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, "Containment Penetrations Fatigue"	II.A3.C-13	3.5-1, 009	A

Table 3.5.2-1: Containment Building 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**
Containment vessel nozzle (mechanical)	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, "Containment Penetrations Fatigue"	II.A3.C-13	3.5-1, 009	A
Flexible membrane (annulus)	Pressure boundary	Silicone	Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B
Fuel transfer penetration sleeve	Fire barrier Pressure boundary Structural support	Dissimilar metal welds	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-38	3.5-1, 010	A
Fuel transfer penetration sleeve	Fire barrier Pressure boundary Structural support	Dissimilar metal welds	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-36	3.5-1, 035	A
Fuel transfer penetration sleeve	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.C-16	3.5-1, 028	A
Fuel transfer penetration sleeve	Fire barrier 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
Fuel transfer penetration sleeve	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, "Containment Penetrations Fatigue"	II.A3.C-13	3.5-1, 009	A

Table 3.5.2-1: Containment Building 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**
Fuel transfer tube, expansion bellows, and flange	Fire barrier Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-38	3.5-1, 010	A
Fuel transfer tube, expansion bellows, and flange	Fire barrier Pressure boundary 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.AP-79	3.3-1, 125	D
Fuel transfer tube, expansion bellows, and flange	Fire barrier Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, "Containment Penetrations Fatigue"	II.A3.C-13	3.5-1, 009	A
Interior beams, fill, shields, slabs, and walls (accessible)	Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	III.A1.TP-25	3.5-1, 054	B
Interior beams, fill, shields, slabs, and walls (accessible)	Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking, loss of bond, loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-26	3.5-1, 066	B
Interior beams, fill, shields, slabs, and walls (accessible)	Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Increase in porosity and permeability, cracking, loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-28	3.5-1, 067	B

Table 3.5.2-1: Containment Building 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**
Interior beams, fill, shields, slabs, and walls (inaccessible)	Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	III.A1.TP-204	3.5-1, 043	B, 3
Interior beams, fill, shields, slabs, and walls (inaccessible)	Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking, loss of bond, loss of material	Structures Monitoring (B.2.3.33)	II.A2.CP-75	3.5-1, 023	D
Masonry walls	Shelter, protection Structural support	Concrete block (unreinforced)	Air – indoor uncontrolled	Cracking	Masonry Walls (B.2.3.32)	III.A1.T-12	3.5-1, 070	A
Masonry walls	Shelter, protection Structural support	Concrete block (reinforced)	Air – indoor uncontrolled	Cracking	Masonry Walls (B.2.3.32)	III.A1.T-12	3.5-1, 070	A
Miscellaneous steel (missile barriers, hatch frame covers, framing for radiant energy shields, etc.)	Fire barrier Missile barrier Shelter, protection 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	C
Miscellaneous steel (missile barriers, hatch frame covers, framing for radiant energy shields, etc.)	Fire barrier Missile barrier Shelter, protection Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B5.TP-3	3.5-1, 089	C

Table 3.5.2-1: Containment Building 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**
Miscellaneous steel (missile barriers, hatch frame covers, framing for radiant energy shields, etc.)	Fire barrier Missile barrier Shelter, protection Structural support	Galvanized steel	Air-indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	A
Miscellaneous steel (missile barriers, hatch frame covers, framing for radiant energy shields, etc.)	Fire barrier Missile barrier Shelter, protection Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Penetration seals and gaskets	Pressure boundary	Elastomer	Air – indoor uncontrolled	Loss of sealing	10 CFR Part 50, Appendix J (B.2.3.31)	II.A3.CP-41	3.5-1, 033	A
Penetrations (electrical), Unit 1	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A, 1
Penetrations (electrical), Unit 1	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.C-16	3.5-1, 028	A
Penetrations (electrical), Unit 1	Fire barrier 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
Penetrations (electrical), Unit 2	Fire barrier Pressure boundary Structural support	Dissimilar metal welds	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A, 1

Table 3.5.2-1: Containment Building 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
Penetrations (electrical), Unit 2	Fire barrier Pressure boundary Structural support	Dissimilar metal welds	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-36	3.5-1, 035	A
Penetrations (electrical), Unit 2	Fire barrier Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-37	3.5-1, 027	A, 1
Penetrations (mechanical), including bellows	Fire barrier Pressure boundary Structural support	Dissimilar metal welds	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-38	3.5-1, 010	A, 4
Penetrations (mechanical), including bellows	Structural support Pressure boundary	Dissimilar metal welds	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-36	3.5-1, 035	A
Penetrations (mechanical), including bellows	Fire barrier Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-38	3.5-1, 010	A, 4
Penetrations (mechanical), including bellows	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B.2.3.31) ASME Section XI, Subsection IWE (B.2.3.29)	II.A3.CP-36	3.5-1, 035	A
Penetrations (mechanical), including bellows	Fire barrier 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

Table 3.5.2-1: Containment Building 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**
Penetrations (mechanical), including bellows	Fire barrier Pressure boundary Structural support	Dissimilar metal welds	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, "Containment Liner Plate, Metal Containments, and Penetrations Fatigue"	II.A3.C-13	3.5-1, 009	A
Penetrations (mechanical), including bellows	Fire barrier Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, "Containment Liner Plate, Metal Containments, and Penetrations Fatigue"	II.A3.C-13	3.5-1, 009	A
Penetrations (mechanical), including bellows	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, "Containment Liner Plate, Metal Containments, and Penetrations Fatigue"	II.A3.C-13	3.5-1, 009	A
Penetrations (mechanical), thermal insulation (type I hot penetrations)	Insulate (thermal)	Calcium silicate	Air – indoor uncontrolled	None	None	VIII.H.S-403	3.4-1, 064	I, 5
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)	N/A	N/A	F, 6
Pressure retaining bolting	Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled	Loss of preload	ASME Section XI, Subsection IWE (B.2.3.29)	N/A	N/A	F, 6
Pressure retaining bolting	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of preload	10 CFR Part 50, Appendix J (B.2.3.31) 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 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
Pressure retaining bolting	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
Primary shield wall	Radiation shielding Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Loss of mechanical properties; reduction of strength	Structures Monitoring (B.2.3.33)	III.A4.T-35	3.5-1, 097	B, 7
RCS Class 1 support bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-229	3.5-1, 087	B
RCS Class 1 support bolting	Structural support	Steel	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-41	3.5-1, 068	B
RCS Class 1 support bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.T-24	3.5-1, 091	B
RCS Class 1 support bolting	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
RCS Class 1 supports	Structural support	Steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.T-24	3.5-1, 091	B
RCS 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	A
Reactor cavity seal ring	Pressure boundary	Stainless steel	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B2.T-37b	3.5-1, 100	D
Reactor cavity seal ring	Pressure boundary	Stainless steel	Treated borated water	Cracking Loss of material	Water Chemistry (B.2.3.2) and monitoring of the pool water level	III.A5.T-14	3.5-1, 078	A

Table 3.5.2-1: Containment Building 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
Reactor cavity seal ring seals	Pressure boundary	Elastomer	Air – indoor uncontrolled; treated borated water	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	D
Refueling cavity liner plate	Pressure boundary	Stainless steel	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B5.T-37b	3.5-1, 100	D
Refueling cavity liner plate	Pressure boundary	Stainless steel	Treated borated water	Cracking Loss of material	Water Chemistry (B.2.3.2) and monitoring of the pool water level and leakage from the leak chase channels	III.A5.T-14	3.5-1, 078	A
Refueling upender (passive components)	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
RV supports and bolting	Structural support	Steel	Air-indoor uncontrolled	Loss of fracture toughness	ASME Section XI, Subsection IWF (B.2.3.30)	N/A	N/A	H, 8
Service Level I coatings	Coating integrity	Coatings	Air – indoor uncontrolled	Loss of coating or lining integrity	Protective Coating Monitoring and Maintenance (B.2.3.35)	II.A3.CP-152	3.5-1, 034	A
Service Level I coatings	Coating integrity	Coatings	Air – indoor uncontrolled	Loss of coating or lining integrity	Protective Coating Monitoring and Maintenance (Section B.2.3.35)	II.A3.CP-152	3.5-1, 073	A
Shield building airtight bulkhead door seals	Pressure boundary Shelter, protection	Elastomer	Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	D
Shield building airtight bulkhead door seals	Pressure boundary Shelter, protection	Elastomer	Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	D

Table 3.5.2-1: Containment Building 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
Shield building airtight bulkhead doors	Pressure boundary Shelter, protection	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Shield building airtight bulkhead doors	Pressure boundary Shelter, protection	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Shield building exterior walls (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Increase in porosity and permeability, cracking, loss of material	Structures Monitoring (B.2.3.33)	II.A2.CP-71	3.5-1, 024	B
Shield building exterior walls and roof (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	III.A2.TP-25	3.5-1, 054	B
Shield building exterior walls and roof (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A2.TP-25	3.5-1, 054	B
Shield building exterior walls and roof (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking, loss of bond, loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-26	3.5-1, 066	B
Shield building exterior walls and roof (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking, loss of bond, loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-26	3.5-1, 066	B
Shield building exterior walls and roof (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Increase in porosity and permeability, cracking, loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-28	3.5-1, 067	B

Table 3.5.2-1: Containment Building 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
Shield building exterior walls and roof (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Increase in porosity and permeability, cracking, loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-28	3.5-1, 067	B
Shield building exterior walls and roof (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/Soil (outdoor) and Concrete (indoor)	Cracking	Structures Monitoring (B.2.3.33)	III.A1.TP-204	3.5-1, 043	B, 9
Shield building exterior walls and roof (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/Soil (outdoor) and Concrete (indoor)	Cracking, loss of bond, loss of material	Structures Monitoring (B.2.3.33)	II.A2.CP-75	3.5-1, 023	B
Shield building foundation / base mat (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	II.A2.CP-58	3.5-1, 019	B
Shield building foundation / base mat (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking; loss of bond; loss of material	Structures Monitoring (B.2.3.33)	II.A2.CP-74	3.5-1, 021	B
Shield building foundation / base mat (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Increase in porosity and permeability, cracking, loss of material	Structures Monitoring (B.2.3.33)	III.A2.TP-28	3.5-1, 067	B
Shield building foundation / base mat (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	II.A2.CP-104	3.5-1, 012	B, 10
Shield building foundation / base mat (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking; loss of bond; loss of material	Structures Monitoring (B.2.3.33)	II.A2.CP-75	3.5-1, 023	B

Table 3.5.2-1: Containment Building 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
Shield building foundation / base mat (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Increase in porosity and permeability, cracking, loss of material	Structures Monitoring (B.2.3.33)	II.A2.CP-71	3.5-1, 024	B
Shield building foundation / base mat (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A1.TP-30	3.5-1, 044	B
Shield building foundation / base mat (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Water-flowing	Increase in porosity and permeability, loss of strength	Structures Monitoring (B.2.3.33)	II.A2.CP-53	3.5-1, 014	B
Shield building outside door (maintenance hatch)	Shelter, protection	Concrete	Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A2.TP-25	3.5-1, 054	B
Shield building outside door (maintenance hatch)	Shelter, protection	Concrete	Air – outdoor	Cracking; loss of bond; loss of material	Structures Monitoring (B.2.3.33)	II.A2.CP-74	3.5-1, 021	B
Shield building outside door (maintenance hatch)	Shelter, protection	Concrete	Air – outdoor	Increase in porosity and permeability, cracking, loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-28	3.5-1, 067	B
Sliding surfaces	Structural support	Lubrite®	Air – indoor uncontrolled	Loss of mechanical function	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-45	3.5-1, 075	B
Trisodium Phosphate (TSP) baskets, Unit 2	Shelter, protection Structural support	Stainless steel	Air – indoor uncontrolled	Loss of material, cracking	Structures Monitoring (B.2.3.33)	III.B2.T-37b	3.5-1, 100	D

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.
F. Material not in NUREG-2191 for this component.
H. Aging effect not in NUREG-2191 for this component, material, and environment combination.
I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

Plant Specific Notes

1. Consistent with SLR-ISG-2021-03-STRUCTURES, Appendix A, Containment components with no fatigue analysis or waiver are susceptible to cracking due to cyclic loading.
2. Manway at the top of the Containment Vessel is a permanently sealed (welded) shut part of the Containment Vessel.
3. Consistent with SLR-ISG-2021-03-STRUCTURES, the Structures Monitoring (B.2.3.33) AMP manages loss of material for stainless steel exposed to air, instead of plant-specific program, whereas cracking due to SCC of the same penetration components is managed by 10 CFR Part 50, Appendix J and ASME Section XI Subsection IWE AMPs.
4. Eight Type III (semi-hot) penetration assemblies per unit and, conservatively, both unit's fuel transfer tubes are stainless steel or dissimilar metal weld and exposed to process temperatures > 140°F during normal plant operation and, therefore, susceptible to stress corrosion.
5. Insulation for main steam and feedwater penetrations are fully encased in the multiple flued head and guard pipes and there are no plausible moisture, contaminants, or exposures that could degrade the (calcium silicate) insulation.
6. Stainless steel penetration assemblies include stainless steel pressure-retaining bolting that is managed by the ASME Section XI, Subsection IWE AMP.
7. Irradiation of the concrete primary shield wall is addressed in Section 3.5.2.2.2.6 and is managed by the Structures Monitoring (B.2.3.33) AMP.
8. The loss of fracture toughness aging effect due to irradiation embrittlement of the steel reactor vessel supports and bolting is addressed in Section 3.5.2.2.2.7 and is managed by the ASME Section XI, Subsection IWF (B.2.3.30) AMP.
9. Consistent with SLR-ISG-2021-03-STRUCTURES, the Structures Monitoring AMP manages cracking of concrete due to reaction with aggregates.
10. Bottom portion and bottom head of the Containment Vessel are completely encased in concrete fill inside the (Group 1) Shield Building. The operating floor inside the Containment Vessel is this concrete fill.

Table 3.5.2-2: Component Cooling Water Area 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**
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP 8	3.5 1, 095	A
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-302	3.5-1, 077	B
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-274	3.5-1, 082	D
Concrete: columns, foundation, pedestals, roof, shield walls, (accessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A7.TP-25	3.5-1, 054	B
Concrete: columns, foundation, pedestals, roof, shield walls, (accessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-26	3.5-1, 066	B
Concrete: columns, foundation, pedestals, roof, shield walls, (accessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A7.TP-24	3.5-1, 063	B, 1
Concrete: columns, pedestals, roof, shield walls, slabs	Fire barrier Flood protection 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.2.3.33)	III.A7.TP-28	3.5-1, 067	B

Table 3.5.2-2: Component Cooling Water Area 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: foundation	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A7.TP-30	3.5-1, 044	B
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-212	3.5-1, 065	B
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-29	3.5-1, 067	B
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A7.TP-204	3.5-1, 043	B, 2
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A7.TP-67	3.5-1, 047	B, 1, 2
Missile barriers (Unit 1 only)	Missile barrier Shelter, protection	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-302	3.5-1, 077	B
Missile protection doors (Unit 2 only)	Missile barrier Shelter, protection	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-302	3.5-1, 077	B
Structural bolting	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A7.TP-261	3.5-1, 088	B
Structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-274	3.5-1, 082	B
Structural steel: beams, columns	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-302	3.5-1, 077	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. Groundwater is considered to be water-flowing.
2. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURE, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.

Table 3.5.2-3: Condensate Polisher Building – Summary 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	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5-1, 067	B
Concrete: foundation, roof, slabs, walls (accessible)	Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B
Concrete: foundation, roof, slabs, walls (accessible)	Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Concrete: foundation, walls (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Concrete: foundation, walls (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Concrete: foundation, walls (inaccessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2
Concrete: roof, slabs, walls	Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Concrete: roof, walls (accessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B

General Notes

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURE, "Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance".
2. Groundwater is considered to be water-flowing.

Table 3.5.2-4: Condensate Storage Tank Enclosures – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	A
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-302	3.5-1, 077	B
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B5.TP-274	3.5-1, 082	D
Concrete: foundation/base mat	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A7.TP-30	3.5-1, 044	B
Concrete: foundation/base mat, dome, shield walls, etc.	Fire 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.2.3.33)	III.A7.TP-28	3.5-1, 067	B
Concrete: foundation/base mat, ring pedestals (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-212	3.5-1, 065	B
Concrete: foundation/base mat, ring pedestals (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-29	3.5-1, 067	B
Concrete: foundation/base mat, ring pedestals (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A7.TP-204	3.5-1, 043	B, 1

Table 3.5.2-4: Condensate Storage Tank Enclosures – Summary 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/base mat, ring pedestals (inaccessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A7.TP-67	3.5-1, 047	B, 1, 2
Concrete: roof/dome, shield walls (Unit 2 only) (accessible)	Fire barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A7.TP-25	3.5-1, 054	B
Concrete: roof/dome, shield walls (Unit 2 only) (accessible)	Fire barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-26	3.5-1, 066	B
Concrete: roof/dome, shield walls (Unit 2 only) (accessible)	Fire barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A7.TP-24	3.5-1, 063	B, 1
Missile protection hood (Unit 2 only)	Missile barrier	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-302	3.5-1, 077	B
Structural bolting	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A8.TP-261	3.5-1, 088	B
Structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-274	3.5-1, 082	B
Structural steel	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-302	3.5-1, 077	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURE, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.
2. Groundwater is considered to be water-flowing.

Table 3.5.2-5: Diesel Oil Equipment Enclosures – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	A
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	D
Concrete: enclosure foundations	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Concrete: enclosure foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Concrete: enclosure foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5-1, 067	B
Concrete: enclosure foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Concrete: enclosure foundations (inaccessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2
Concrete: enclosure foundations, roof, walls (accessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B

Table 3.5.2-5: Diesel Oil Equipment Enclosures – Summary 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: roof, slabs, walls	Fire barrier Flood protection 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.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Concrete: roof, slabs, walls (accessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B
Concrete: roof, slabs, walls (accessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Diesel oil storage tanks foundations	Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Diesel oil storage tanks foundations	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Diesel oil storage tanks foundations (accessible)	Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B
Diesel oil storage tanks foundations (accessible)	Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B

Table 3.5.2-5: Diesel Oil Equipment Enclosures – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Diesel oil storage tanks foundations (accessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B
Diesel oil storage tanks foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Diesel oil storage tanks foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5-1, 067	B
Diesel oil storage tanks foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Diesel oil storage tanks foundations (inaccessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2
Miscellaneous steel (i.e., missile barrier doors) (Unit 2 only)	Fire barrier Missile barrier	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-302	3.5-1, 077	B
Structural bolting	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5-1, 088	B
Structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURE, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.
2. Groundwater is considered to be water-flowing.

Table 3.5.2-6: Emergency Diesel Generator Buildings – Summary 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 exhaust barrier plates structure	Direct flow Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Air intake deflector plate	Direct flow	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Air intake diverter structure (roof)	Direct flow	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Concrete air inlet louvers (foundation, slabs, walls)	Direct flow Structural support	Concrete (reinforced)	Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Concrete air inlet louvers (foundation, slabs, walls) (accessible)	Direct flow Structural support	Concrete (reinforced)	Air – outdoor Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B
Concrete air inlet louvers (foundation, slabs, walls) (accessible)	Direct flow Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B
Concrete air inlet louvers (foundation, slabs, walls) (accessible)	Direct flow Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Concrete air inlet louvers foundation	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Concrete air inlet louvers foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Concrete air inlet louvers foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B, 1

Table 3.5.2-6: Emergency Diesel Generator Buildings – Summary 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 air inlet louvers foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5-1, 067	B, 1
Concrete air inlet louvers foundation (inaccessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2
Concrete: foundation/base mat, walls (inaccessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Concrete: foundation/base mat, walls (inaccessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5-1, 067	B
Concrete: foundation/base mat, walls (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Concrete: foundation/base mat, walls (inaccessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2
Concrete: slabs, walls, roofs	Fire barrier Flood protection 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.2.3.33)	III.A3.TP-28	3.5-1, 067	B

Table 3.5.2-6: Emergency Diesel Generator Buildings – Summary 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: slabs, walls, roofs, trenches (accessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B
Concrete: slabs, walls, roofs, trenches (accessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Concrete: slabs, walls, roofs, trenches	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Concrete: walls, roofs (accessible)	Fire barrier Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B
Exterior louvers (for ventilation and missile protection) (Unit 1 only)	Missile barrier Shelter, protection	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-274	3.5-1, 082	D
Exterior louvers (for ventilation and missile protection) (Unit 1 only)	Missile barrier Shelter, protection	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Miscellaneous steel	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Missile protection doors	Flood protection Missile barrier	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B

Table 3.5.2-6: Emergency Diesel Generator Buildings – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Missile protection exhaust hoods (Unit 2 only)	Missile barrier Shelter, protection	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Missile protection exhaust hoods (Unit 2 only)	Missile barrier Shelter, protection	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-274	3.5-1, 082	D
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5-1, 088	B
Structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B

General Notes

B. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURE, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.
2. Groundwater is considered to be water-flowing.

Table 3.5.2-7: Fuel Handling Buildings – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Airtight seals (doors)	Pressure boundary	Elastomers	Air – indoor uncontrolled Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B
Boral®	Absorb neutrons	Aluminum alloy Boron carbide	Treated borated water	Reduction of neutron absorbing capacity Change in dimensions Loss of material	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.3.26)	VII.A2.AP-235	3.3-1, 102	A
Cask removal L-shape Hatch	Missile barrier Shelter, protection	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A5.TP-25	3.5-1, 054	B
Cask removal L-shape Hatch	Missile barrier Shelter, protection	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A5.TP-24	3.5-1, 063	B
Cask removal L-shape Hatch	Missile barrier Shelter, protection	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A5.TP-26	3.5-1, 066	B
Cask removal L-shape Hatch	Missile barrier Shelter, protection	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A5.TP-28	3.5-1, 067	B
Checkered plate, grating, handrails, ladders, platforms, stairs	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
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B5.TP-3	3.5-1, 089	C

Table 3.5.2-7: Fuel Handling Buildings – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A5.TP-302	3.5-1, 077	B
Concrete: columns, fuel pool and transfer canal walls, roofs, slabs, walls (accessible)	Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A5.TP-25	3.5-1, 054	B
Concrete: columns, fuel pool and transfer canal walls, roofs, slabs, walls (accessible)	Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A5.TP-26	3.5-1, 066	B
Concrete: foundation/base mat	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A5.TP-30	3.5-1, 044	B
Concrete: foundation/base mat (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A5.TP-212	3.5-1, 065	B
Concrete: foundation/base mat (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A5.TP-29	3.5-1, 067	B

Table 3.5.2-7: Fuel Handling Buildings – Summary 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/base mat, fuel pool and transfer canal walls, walls	Flood protection 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.2.3.33)	III.A5.TP-28	3.5-1, 067	B
Concrete: foundation/base mat, fuel pool and transfer canal walls, walls (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A5.TP-204	3.5-1, 043	B, 1
Concrete: foundation/base mat, fuel pool and transfer canal walls, walls (inaccessible)	Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A5.TP-67	3.5-1, 047	B, 1, 2, 3
Concrete: roof, walls (accessible)	Flood protection Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A5.TP-24	3.5-1, 063	B
Fuel pool gates	Pressure boundary	Stainless steel	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B5.T-37b	3.5-1, 100	D
Fuel pool gates	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	III.A5.T-14	3.5-1, 078	C, 4

Table 3.5.2-7: Fuel Handling Buildings – Summary 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 upender (passive components)	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	C
HVAC louver	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B4.TP-43	3.5-1, 092	B
Masonry wall (Unit 2 Only)	Shelter, protection Structural support	Concrete block (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Masonry Walls (B.2.3.32)	III.A5.T-12	3.5-1, 070	A
Masonry wall (Unit 1 Only)	Shelter, protection	Concrete block (unreinforced)	Air – indoor uncontrolled	Cracking	Masonry Walls (B.2.3.32)	III.A5.T-12	3.5-1, 070	A
Metamic® inserts	Absorb neutrons	6061 aluminum alloy reinforced w/ type 1 ASTM C-750 boron carbide	Treated borated water	Reduction of neutron absorbing capacity Change in dimensions Loss of material	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.3.26)	VII.A2.AP-235	3.3-1, 102	A
Miscellaneous steel (i.e., barriers, frame, frame covers, hatch, missile barriers, radiation shielding, etc.)	Missile barrier 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
Miscellaneous steel (i.e., barriers, frame, frame covers, hatch, missile barriers, radiation shielding, etc.)	Missile barrier Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A5.TP-302	3.5.1, 077	D
Pool liner plates	Pressure boundary	Stainless steel	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B5.T-37b	3.5-1, 100	D

Table 3.5.2-7: Fuel Handling Buildings – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pool liner plates	Pressure boundary	Stainless steel	Treated borated water	Cracking Loss of material	Water Chemistry (B.2.3.2) and monitoring of the pool water level and leakage from the leak chase channels	III.A5.T-14	3.5-1, 078	A
Spent fuel pool storage brackets	Structural support	Stainless steel	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B5.T-37b	3.5-1, 100	D
Spent fuel pool storage brackets	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	C
Spent fuel storage racks	Shelter, protection 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	A
Structural bolting	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
Structural bolting	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B5.TP-3	3.5-1, 089	A
Structural bolting	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A5.TP-274	3.5-1, 082	B
Structural bolting/ connections	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A5.TP-248	3.5-1, 080	B
Structural bolting/ connections	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A5.TP-261	3.5-1, 088	B
Structural bolting/ connections	Structural support	Stainless steel	Treated borated water	Loss of preload	One-Time Inspection (B.2.3.20) Water Chemistry (B.2.3.2)	III.A5.TP-261	3.5-1, 088	E, 5

Table 3.5.2-7: Fuel Handling Buildings – Summary 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 framing (beams, columns, connections, etc.)	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.2.T-25	3.5-1, 089	C
Structural steel framing (beams, columns, connections, etc.)	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A5.TP-302	3.5-1, 077	B
Weatherproofing	Shelter, protection	Caulking and sealants	Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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 AMP 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. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURE, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance.”
2. Groundwater is considered to be water-flowing.
3. Conservatively, spent fuel pool leakage is identified as water-flowing.
4. There are no leak chase channels to monitor for the fuel pool gates.
5. Structural bolting/connection associated with the spent fuel pool will be managed under the Water Chemistry and One-Time Inspection AMP's.

Table 3.5.2-8: Intake, Discharge, and Emergency Cooling Canals – Summary 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, erosion protection; concrete paving and grout filled fabric	Structural support Emergency cooling water source	Concrete (reinforced); Grout	Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.T-20	3.5-1, 056	A
Concrete, erosion protection; concrete paving and grout filled fabric	Structural support Emergency cooling water source	Concrete (reinforced); Grout	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A6.TP-30	3.5-1, 044	B
Concrete, erosion protection; concrete paving and grout filled fabric (accessible)	Structural support Emergency cooling water source	Concrete (reinforced); Grout	Air – outdoor Raw water	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.T-34	3.5-1, 096	A
Concrete, erosion protection; concrete paving and grout filled fabric (accessible)	Structural support Emergency cooling water source	Concrete (reinforced); Grout	Air – outdoor Raw water	Increase in porosity and permeability Loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-37	3.5-1, 061	A
Concrete, erosion protection; concrete paving and grout filled fabric (accessible)	Structural support Emergency cooling water source	Concrete (reinforced); Grout	Air – outdoor Raw water	Cracking Loss of bond Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-38	3.5-1, 059	A
Concrete, erosion protection; concrete paving and grout filled fabric (inaccessible)	Structural support Emergency cooling water source	Concrete (reinforced); Grout	Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A6.TP-220	3.5-1, 050	B
Concrete, erosion protection; concrete paving and grout filled fabric (inaccessible)	Structural support Emergency cooling water source	Concrete (reinforced); Grout	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A6.TP-104	3.5-1, 065	B

Table 3.5.2-8: Intake, Discharge, and Emergency Cooling Canals – Summary 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, erosion protection; concrete paving and grout filled fabric (inaccessible)	Structural support Emergency cooling water source	Concrete (reinforced); Grout	Groundwater/soil	Cracking Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A6.TP-107	3.5-1, 067	B
Concrete, erosion protection; concrete paving and grout filled fabric (inaccessible)	Structural support Emergency cooling water source	Concrete (reinforced); Grout	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A6.TP-109	3.5-1, 051	B
Earthen canal dikes	Structural support Emergency cooling water source	Earthen fill	Air – outdoor Water – flowing or standing	Loss of form Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.T-22	3.5-1, 058	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.5.2-9: Intake 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: foundation/base mat, pump pedestals, roofs, slabs, walls	Emergency cooling water source Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.T-20	3.5-1, 056	A
Concrete: foundation/base mat, pump pedestals, roofs, slabs, walls (accessible)	Emergency cooling water source Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor Raw water	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.T-34	3.5-1, 096	A
Concrete: foundation/base mat, pump pedestals, roofs, slabs, walls (accessible)	Emergency cooling water source Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor Raw water	Increase in porosity and permeability Loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-37	3.5-1, 061	A
Concrete: foundation/base mat, pump pedestals, roofs, slabs, walls (accessible)	Emergency cooling water source Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor Raw water	Cracking Loss of bond Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-38	3.5-1, 059	A
Concrete: foundation/base mat, roofs, slabs, walls (inaccessible)	Emergency cooling water source Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A6.TP-109	3.5-1, 051	B
Concrete: foundation/base mat, walls	Emergency cooling water source Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A6.TP-30	3.5-1, 044	B

Table 3.5.2-9: Intake 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: foundation/base mat, walls (inaccessible)	Emergency cooling water source Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A6.TP-220	3.5-1, 050	B
Concrete: foundation/base mat, walls (inaccessible)	Emergency cooling water source Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A6.TP-104	3.5-1, 065	B
Concrete: foundation/base mat, walls (inaccessible)	Emergency cooling water source Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity Loss of strength	Structures Monitoring (B.2.3.33)	III.A6.TP-107	3.5-1, 067	B
Intake level recorder	Structural support	PVC	Concrete	None	None	VII.J.A-709	3.3-1, 184	A
Miscellaneous steel (i.e., missile barriers, hatch, frame covers, etc.)	Missile barrier Shelter, protection Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-302	3.5-1, 077	B
Retaining walls	Structural support	Concrete (reinforced)	Raw water	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.T-34	3.5-1, 096	A
Retaining walls	Structural support	Concrete (reinforced)	Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.T-20	3.5-1, 056	A

Table 3.5.2-9: Intake 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**
Retaining walls	Structural support	Concrete (reinforced)	Raw water	Increase in porosity and permeability Loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-37	3.5-1, 061	A
Retaining walls	Structural support	Concrete (reinforced)	Raw water	Cracking	Structures Monitoring (B.2.3.33)	III.A6.TP-25	3.5-1, 054	B
Structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A6.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A6.TP-261	3.5-1, 088	B
Structural steel framing (columns, beams, connections)	Missile barrier Shelter, protection Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-302	3.5-1, 077	B
Structural steel framing (columns, beams, connections)	Missile barrier Shelter, protection Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	D
Weatherproofing	Shelter, protection	Caulking and sealants	Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

None.

Table 3.5.2-10: Reactor Auxiliary Buildings – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Airtight door seals	Pressure boundary	Elastomers	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B
Airtight doors	Fire barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Checkered plate, grating, handrails, ladders, platforms, stairs	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	C
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B5.TP-3	3.5-1, 089	C
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	C
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Concrete: exterior walls, roofs (accessible)	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B
Concrete: foundation/base mat, exterior walls	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B

Table 3.5.2-10: Reactor Auxiliary Buildings – Summary 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/base mat, exterior walls (inaccessible)	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Concrete: foundation/base mat, exterior walls (inaccessible)	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5-1, 067	B
Concrete: foundation/base mat, exterior walls (inaccessible)	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Concrete: foundation/base mat, exterior walls (inaccessible)	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2
Concrete: roofs, slabs, walls	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Concrete: roofs, slabs, walls (accessible)	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B

Table 3.5.2-10: Reactor Auxiliary Buildings – Summary 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: roofs, slabs, walls (accessible)	Fire barrier Flood protection Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
HVAC louvers	Shelter, protection Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
HVAC louvers	Shelter, protection Structural support	Stainless steel	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B5.T-37b	3.5-1, 100	D
HVAC louvers	Shelter, protection Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	D
Miscellaneous steel (i.e., radiation shielding, missile barriers, hatch frame covers, etc.)	Fire barrier Missile barrier Shelter, protection Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Missile protection doors and barriers	Missile barrier	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Reinforced concrete masonry block walls	Fire barrier Pressure boundary Shelter, protection Structural support	Concrete block (reinforced)	Air – indoor uncontrolled	Cracking	Masonry Walls (B.2.3.32)	III.A3.T-12	3.5-1, 070	A, 3
Structural bolting	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, 090	A
Structural bolting	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B5.TP-3	3.5-1, 089	A
Structural bolting	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5-1, 088	B

Table 3.5.2-10: Reactor Auxiliary Buildings – Summary 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	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B
Structural steel framing (columns, beams, connections, etc.)	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	C
Structural steel framing (columns, beams, connections, etc.)	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Unreinforced concrete masonry block walls	Fire barrier Shelter, protection Structural support	Concrete block (unreinforced)	Air – indoor uncontrolled	Cracking	Masonry Walls (B.2.3.32)	III.A3.T-12	3.5-1, 070	A
Watertight door seals	Flood protection Pressure boundary	Elastomers	Air – indoor uncontrolled Air – indoor controlled Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B
Watertight doors	Flood protection Pressure boundary	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Weatherproofing	Shelter, protection	Caulking and sealants	Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURES, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance.”
2. Groundwater is considered to be water-flowing.
3. The structural component provides a pressure boundary intended function for Halon in the Unit 1 cable spreading room or the control room envelope.

Table 3.5.2-11: Steam Trestle Areas – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Concrete: (accessible; above grade)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Concrete: (accessible; interior and above-grade exterior)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Concrete: foundations	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Concrete: foundations (accessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B
Concrete: foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Concrete: foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5-1, 067	B
Concrete: foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Concrete: foundations (inaccessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2
Concrete: foundations, slabs (accessible)	Fire barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B

Table 3.5.2-11: Steam Trestle Areas – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Miscellaneous steel (i.e., missile barriers, steel grating, etc.)	Fire barrier Missile barrier Shelter, protection Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Miscellaneous steel (i.e., missile barriers, steel grating, etc.)	Fire barrier Missile barrier Shelter, protection Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	D
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5-1, 088	B
Structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B
Structural steel framing (columns, beams, connections, etc.)	Missile barrier Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B

General Notes

B. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURES, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.
2. Groundwater is considered to be water-flowing.

Table 3.5.2-12: Switchyard – Summary 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: circuit breakers, control buildings, start-up transformers, transmission towers; covered cable trenches	Shelter, protection Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 040	B
Concrete foundations: circuit breakers, control buildings, start-up transformers, transmission towers; covered cable trenches (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Concrete foundations: circuit breakers, control buildings, start-up transformers, transmission towers; covered cable trenches (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5-1, 067	B
Concrete foundations: circuit breakers, control buildings, start-up transformers, transmission towers; covered cable trenches (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1

Table 3.5.2-12: Switchyard – Summary 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: circuit breakers, control buildings, start-up transformers, transmission towers; covered cable trenches (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2
Concrete foundations: circuit breakers, start-up transformers, transmission towers; covered cable trenches (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B
Concrete foundations: circuit breakers, start-up transformers, transmission towers; covered cable trenches (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5-1, 065	B
Concrete: control building walls, foundations, roof, slabs; circuit breakers, start-up transformers, transmission towers	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B

Table 3.5.2-12: Switchyard – Summary 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: control building walls, foundations, roof, slabs; circuit breakers, start-up transformers, transmission towers; covered cable trenches (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Concrete: control building walls, foundations, roof, slabs; circuit breakers, start-up transformers, transmission towers; covered cable trenches (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B
Masonry block walls (control building)	Shelter, protection Structural support	Concrete block (reinforced)	Air – outdoor	Cracking	Masonry Walls (B.2.3.32)	III.A3.T-12	3.5-1, 070	A
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5-1, 088	B
Structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B
Transmission towers	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	D
Weatherproofing (switchyard control building)	Shelter, protection	Caulking and sealants	Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURES, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.
2. Groundwater is considered to be water-flowing.

Table 3.5.2-13: Turbine Buildings – Summary 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 curbs (Unit 2, 2B switchgear room) (accessible)	Fire protection	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B
Concrete curbs (Unit 2, 2B switchgear room) (accessible)	Fire protection	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Concrete curbs (Unit 2, 2B switchgear room) (accessible)	Fire protection	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Concrete: foundation/base mat	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Concrete: foundation/base mat (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Concrete: foundation/base mat (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5-1, 067	B
Concrete: foundation/base mat (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Concrete: foundation/base mat (inaccessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2
Concrete: slabs	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Concrete: slabs (accessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B
Concrete: slabs (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B

Table 3.5.2-13: Turbine Buildings – Summary 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: slabs (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5-1, 088	B
Structural steel framing (columns, beams, connections, etc.)	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Turbine generator casings (covers)	Missile barrier	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Unreinforced concrete masonry block walls (switchgear rooms)	Structural support	Concrete block (unreinforced)	Air – indoor uncontrolled Air – outdoor	Cracking	Masonry Walls (B.2.3.32)	III.A3.T-12	3.5-1, 070	A
Weatherproofing	Shelter, protection	Caulking and sealants	Air – indoor uncontrolled Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURES, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.
2. Groundwater is considered to be water-flowing.

Table 3.5.2-14: Ultimate Heat Sink Dam (Barrier Wall) – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	A
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Checkered plate, grating, handrails, ladders, platforms, stairs	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	C
Concrete: foundation	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A6.TP-30	3.5-1, 044	B
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A6.TP-220	3.5-1, 050	B
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A6.TP-104	3.5-1, 065	B
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A6.TP-107	3.5-1, 067	B
Concrete: foundation (inaccessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A6.TP-109	3.5-1, 051	B
Concrete: foundations, roof, slabs, walls	Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-20	3.5-1, 056	A

Table 3.5.2-14: Ultimate Heat Sink Dam (Barrier Wall) – Summary 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, roof, slabs, walls (accessible)	Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Raw water	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.T-34	3.5-1, 096	A
Concrete: foundations, roof, slabs, walls (accessible)	Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Raw water	Increase in porosity and permeability Loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-37	3.5-1, 061	A
Concrete: foundations, roof, slabs, walls (accessible)	Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Raw water	Cracking Loss of bond Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-38	3.5-1, 059	A
Concrete: foundations, roof, slabs, walls	Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.T-20	3.5-1, 056	A
Miscellaneous steel (i.e., hatch covers, missile barriers, etc.)	Missile barrier Shelter, protection	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A8.TP-302	3.5-1, 077	B
Steel sheet piling (beneath dam)	Shelter, protection	Steel	Groundwater/soil	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-219	3.5-1, 079	B
Structural bolting	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A6.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A6.TP-261	3.5-1, 088	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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.

Plant Specific Notes

None.

Table 3.5.2-15: 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 missile shield for diesel oil pipe	Missile barrier	Concrete (reinforced)	Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Concrete missile shield for diesel oil pipe	Missile barrier	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Concrete missile shield for diesel oil pipe (accessible)	Missile barrier	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B
Concrete missile shield for diesel oil pipe (accessible)	Missile barrier	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B
Concrete missile shield for diesel oil pipe (accessible)	Missile barrier	Concrete (reinforced)	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Concrete missile shield for diesel oil pipe (inaccessible)	Missile barrier	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Concrete missile shield for diesel oil pipe (inaccessible)	Missile barrier	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-29	3.5-1, 067	B
Concrete missile shield for diesel oil pipe (inaccessible)	Missile barrier	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Concrete missile shield for diesel oil pipe (inaccessible)	Missile barrier	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2

Table 3.5.2-15: 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**
Discharge canal nose wave protection (concrete cap)	Flood protection	Concrete (reinforced)	Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Discharge canal nose wave protection (concrete cap)	Flood protection	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Discharge canal nose wave protection (concrete cap) (inaccessible)	Flood protection	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Discharge canal nose wave protection (concrete cap) (inaccessible)	Flood protection	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-29	3.5-1, 067	B
Discharge canal nose wave protection (concrete cap) (inaccessible)	Flood protection	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Discharge canal nose wave protection (concrete cap) (inaccessible)	Flood protection	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2
Discharge canal nose wave protection (concrete cap) (accessible)	Flood protection	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B
Discharge canal nose wave protection (concrete cap) (accessible)	Flood protection	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B

Table 3.5.2-15: 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**
Discharge canal nose wave protection (concrete cap) (accessible)	Flood protection	Concrete (reinforced)	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Discharge canal nose wave protection (sheet piling)	Flood protection	Steel	Groundwater/soil; Concrete	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-219	3.5-1, 079	B
Electrical duct banks and manholes	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Electrical duct banks and manholes	Shelter, protection Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Electrical duct banks and manholes (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B
Electrical duct banks and manholes (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Electrical duct banks and manholes (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Electrical duct banks and manholes (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-29	3.5-1, 067	B

Table 3.5.2-15: 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
Electrical duct banks and manholes (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Electrical duct banks and manholes (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2
Foundations	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2, 3
Foundations	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1, 3
Foundations	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B, 3
Foundations	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B, 3
Foundations	Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B, 3
Foundations	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B, 3
Foundations	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-29	3.5-1, 067	B, 3
Foundations	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B, 3

Table 3.5.2-15: 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
Foundations	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B, 3
Reinforced concrete pipe trenches	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Reinforced concrete pipe trenches	Shelter, protection Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Reinforced concrete pipe trenches (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B
Reinforced concrete pipe trenches (accessible)	Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Reinforced concrete pipe trenches (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Reinforced concrete pipe trenches (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A7.TP-29	3.5-1, 067	B
Reinforced concrete pipe trenches (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Reinforced concrete pipe trenches (inaccessible)	Shelter, protection Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2

Table 3.5.2-15: 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**
Steel missile shield for diesel oil pipe (Unit 2 only	Missile barrier	Steel	Soil	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-219	3.5-1, 079	D
Structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B
Transmission towers	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	D
Weatherproofing	Shelter, protection	Caulking and sealants	Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B

General Notes

B. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURES, “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance”.
2. Groundwater is considered to be water-flowing.
3. Foundations for: fire pumps, pipe supports, city water tanks, refueling water tanks, and Unit 2 primary water tank, hydropneumatic tank, domestic water pumps, start-up transformers, transmission towers, nonsegregated phase bus/cable tray support, and 4.16 kV switchgear.

Table 3.5.2-16: Component Support Commodity – Summary 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 with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B5.T-25	3.5-1, 089	C
Anchorage / embedment	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.33)	III.B3.TP-261	3.5-1, 088	B
Anchorage / embedment	Structural support	Stainless steel	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B3.T-37b	3.5-1, 100	B
Anchorage / embedment	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B3.TP-248	3.5-1, 080	B
ASME class 1 structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-226	3.5-1, 081	B, 1
ASME class 1 structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-229	3.5-1, 087	B, 1
ASME class 1 structural bolting	Structural support	High -strength steel	Air	Cracking	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-41	3.5-1, 068	B, 1
ASME class 1 (non-RCS) pipe supports and component supports	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.T-24	3.5-1, 091	B, 1
ASME class 1 (non-RCS) pipe supports and component 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	A, 1
ASME class 2 and 3 structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.TP-235	3.5-1, 086	B
ASME class 2 and 3 structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.TP-229	3.5-1, 087	B
ASME class 2 and 3 structural bolting	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.2.T-25	3.5-1, 089	A

Table 3.5.2-16: Component Support Commodity – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
ASME class 2 and class 3 pipe supports and component supports	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.T-24	3.5-1, 091	B
ASME class 2 and class 3 pipe supports and component supports	Structural support	Steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B1.2.T-25	3.5-1, 089	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural support	Concrete; grout	Air – indoor uncontrolled Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring (B.2.3.33)	III.B2.TP-42	3.5-1, 055	B
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.2.3.33)	III.B2.TP-42	3.5-1, 055	D
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.2.3.33)	III.B2.TP-42	3.5-1, 055	D
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.2.3.33)	III.B5.TP-42	3.5-1, 055	D
Component supports (nonsafety-related)	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
Component supports (nonsafety-related)	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B2.TP-3	3.5-1, 089	A
Component supports (nonsafety-related)	Structural support	Aluminum Stainless steel	Air	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B2.T-37b	3.5-1, 100	B

Table 3.5.2-16: Component Support Commodity – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Component supports (nonsafety-related)	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B2.TP-43	3.5-1, 092	B
Component supports (nonsafety-related)	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B2.TP-6	3.5-1, 093	B
Conduits and cable trays	Shelter, protection 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	C
Conduits and cable trays	Shelter, protection Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B2.TP-3	3.5-1, 089	C
Conduits and cable trays	Shelter, protection Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A
Conduits and cable trays	Shelter, protection Structural support	Aluminum	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B2.T-37b	3.5-1, 100	D
Conduits and cable trays	Shelter, protection Structural support	Stainless steel	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B2.T-37b	3.5-1, 100	D
Conduits and cable trays	Shelter, protection Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.B2.TP-43	3.5-1, 092	D
Conduits and cable trays	Shelter, protection Structural support	Steel; galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B2.TP-274	3.5-1, 082	D

Table 3.5.2-16: Component Support Commodity – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Conduits (non-metallic)	Shelter, protection Structural support	PVC	Air – outdoor (not in direct sunlight)	None	None	VII.G.A-458	3.3-1, 172	A
Constant and variable load spring hangers; guides; stops	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of mechanical function	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.T-28	3.5-1, 057	B
Electrical and instrument panel and enclosure supports	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
Electrical and instrument panel and enclosure supports	Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B3.TP-3	3.5-1, 089	A
Electrical and instrument panel and enclosure supports	Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Electrical and instrument panel and enclosure supports	Structural support	Steel	Air – indoor controlled	None	None	VIII.I.SP-1	3.4-1, 059	C
Electrical and instrument panel and enclosure supports	Structural support	Stainless steel	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B3.T-37b	3.5-1, 100	B
Electrical and instrument panel and enclosure supports	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B3.TP-43	3.5-1, 092	B
Electrical and instrument panel and enclosure supports	Structural support	Steel; galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B3.TP-274	3.5-1, 082	D
Electrical and instrument panels and enclosures	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 3.5.2-16: Component Support Commodity – Summary 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 and instrument panels and enclosures	Shelter, protection Structural support	Galvanized steel	Air with borated water leakage	Loss of material	Boric Acid Corrosion (B.2.3.4)	III.B3.TP-3	3.5-1, 089	A
Electrical and instrument panels and enclosures	Shelter, protection Structural support	Steel	Air – indoor controlled	None	None	VIII.I.SP-1	3.4-1, 059	C
Electrical and instrument panels and enclosures	Shelter, protection Structural support	Galvanized steel	Air – indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Electrical and instrument panels and enclosures	Shelter, protection Structural support	Stainless steel	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B3.T-37b	3.5-1, 100	B
Electrical and instrument panels and enclosures	Shelter, protection Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B3.TP-43	3.5-1, 092	B
Electrical and instrument panels and enclosures	Shelter, protection Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B3.TP-274	3.5-1, 082	D
Non-metallic thermal insulation	Insulate (thermal)	Any	Air	Reduce thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-422	3.2-1, 087	A
Pipe whip restraints	Pipe whip restraint	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
Pipe whip restraints	Pipe whip restraint	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B5.TP-43	3.5-1, 092	B
Sliding support surfaces (Unit 1 CCW heat exchangers)	Structural support	Graphite lubricated steel	Air – outdoor	Loss of mechanical function	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.TP-45	3.5-1, 075	B, 2

Table 3.5.2-16: Component Support Commodity – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Sliding support surfaces (Unit 2 CCW heat exchangers)	Structural support	Graphite lubricated steel	Air – indoor uncontrolled	Loss of mechanical function	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.TP-45	3.5-1, 075	B, 2
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B5.TP-248	3.5-1, 080	B, 3
Structural bolting	Structural support	Steel	Air	Loss of preload	Structures Monitoring (B.2.3.33)	III.B5.TP-261	3.5-1, 088	B, 3
Structural bolting	Structural support	Galvanized steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B5.TP-274	3.5-1, 082	B, 3

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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 AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant Specific Notes

1. RCS Class 1 supports (inside containment) are addressed in Table 3.5.2-1.
2. Sliding support surfaces for the Unit 1 and Unit 2 CCW heat exchangers will be managed by the ASME Section XI, Subsection IWF AMP.
3. Structural bolting for non-ASME and nonsafety-related supports will be managed under the Structure Monitoring AMP.

Table 3.5.2-17: Fire Rated Assemblies – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Conduit caps	Fire barrier Pressure boundary	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	C
Conduit plugs	Fire barrier Pressure boundary	Silicone foam	Air	Hardening Loss of strength Shrinkage	Fire Protection (B.2.3.15)	VII.G.A-19	3.3-1, 057	B
Conduit plugs	Fire barrier Pressure boundary	Cementitious coating: quelpyre mastic 703B	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-806	3.3-1, 268	B
Conduit plugs	Fire barrier Pressure boundary	Fire retardant coating	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-807	3.3-1, 269	B
Conduit plugs	Fire barrier Pressure boundary	Silicate: ceramic fiber	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-807	3.3-1, 269	B
Fire damper housings	Fire barrier	Steel	Air	Loss of material	Fire Protection (B.2.3.15)	VII.G.A-789	3.3-1, 255	B
Fire doors - airtight	Fire barrier Pressure boundary	Steel	Air	Loss of material	Fire Protection (B.2.3.15)	VII.G.A-21	3.3-1, 059	B
Fire doors - watertight	Fire barrier Flood barrier	Steel	Air	Loss of material	Fire Protection (B.2.3.15)	VII.G.A-21	3.3-1, 059	B
Fire doors (NFPA 805 barriers)	Fire barrier Pressure boundary	Steel	Air	Loss of material	Fire Protection (B.2.3.15)	VII.G.A-21	3.3-1, 059	B

Table 3.5.2-17: Fire Rated Assemblies – Summary 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 sealed isolation joint	Fire barrier	Elastomer: dymeric sealant, ethafoam	Air	Hardening Loss of strength Shrinkage	Fire Protection (B.2.3.15)	VII.G.A-19	3.3-1, 057	B
Fire sealed isolation joint	Fire barrier	Silicates: cerablanket	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-807	3.3-1, 269	B
Fire sealed isolation joint	Fire barrier	Carbon steel plate	Air	Loss of material	Fire Protection (B.2.3.15)	III.B5.TP-43	3.5-1, 092	E, 1
Fire seals: cable tray penetrations	Fire barrier Pressure boundary	Elastomer	Air	Hardening Loss of strength Shrinkage	Fire Protection (B.2.3.15)	VII.G.A-19	3.3-1, 057	B
Fire seals: cable tray penetrations	Fire barrier Pressure boundary	Silicone	Air	Hardening Loss of strength Shrinkage	Fire Protection (B.2.3.15)	VII.G.A-19	3.3-1, 057	B
Fire seals: cable tray penetrations	Fire barrier Pressure boundary	Marinite board Ceramic fiber Fire retardant coating	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-807	3.3-1, 269	B
Fire seals: mechanical penetrations: (Type M-1, M-2, M-3, M-4, M-6, M-7, M-9)	Fire barrier Pressure boundary	Silicone	Air	Hardening Loss of strength Shrinkage	Fire Protection (B.2.3.15)	VII.G.A-19	3.3-1, 057	B
Fire seals: mechanical penetrations: (Type M-1, M-2, M-3, M-4, M-6, M-7, M-9)	Fire barrier Pressure boundary	Silicate: durablanket, ceramic fiber	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-807	3.3-1, 269	B

Table 3.5.2-17: Fire Rated Assemblies – Summary 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 seals: mechanical penetrations: (Type M-1, M-2, M-3, M-4, M-6, M-7, M-9)	Fire barrier Pressure boundary	Aluminum	Air	Cracking Loss of material	Fire Protection (B.2.3.15)	III.B5.T-37b	3.5-1, 100	E, 1
Fire seals: mechanical penetrations: (Type M-1, M-2, M-3, M-4, M-6, M-7, M-9)	Fire barrier Pressure boundary	Stainless steel	Air	Cracking Loss of material	Fire Protection (B.2.3.15)	III.B5.T-37b	3.5-1, 100	E, 1
Fire seals: mechanical penetrations: (Type M-1, M-2, M-3, M-4, M-6, M-7, M-9)	Fire barrier Pressure boundary	Galvanized steel	Air – indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	C
Fire wrap (conduit and steel supports)	Fire barrier	Subliming compound: thermo-lag 330-1	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-805	3.3-1, 267	B
Flame impingement shields (insulating blankets for cable trays)	Fire barrier	Insulating blankets (B&B or Mecatiss)	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-807	3.3-1, 269	B
Miscellaneous barriers	Fire barrier Pressure boundary	Subliming compounds: thermo-lag 330-1 (panels, wrap, spray, or troweled) Thermo-lag 770-1 (panels)	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-805	3.3-1, 267	B

Table 3.5.2-17: Fire Rated Assemblies – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Miscellaneous barriers	Fire barrier Pressure boundary	Ceramic fiber (panels)	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-807	3.3-1, 269	B
Miscellaneous barriers	Fire barrier Pressure boundary	Stainless steel sheet metal (panels)	Air	Cracking Loss of material	Fire Protection (B.2.3.15)	III.B5.T-37b	3.5-1, 100	E, 1
Radiant energy shields	Fire barrier	Subliming compound: thermo-lag 330-1	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-805	3.3-1, 267	B
Radiant energy shields	Fire barrier	Insulating blankets (B&B or Mecatiss)	Air	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-807	3.3-1, 269	B
Radiant energy shields	Fire barrier	Stainless steel	Air	Cracking Loss of material	Fire Protection (B.2.3.15)	III.B5.T-37b	3.5-1, 100	E, 1

General Notes

B. Consistent with component, material, environment, aging effect, and AMP 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. Metal components of fire barrier assemblies will be managed by the Fire Protection AMP.

Table 3.5.2-18: Overhead Heavy Load Handling Systems – Summary 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	Structural support	Concrete (reinforced)	Soil	Cracking and distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5-1, 044	B
Concrete: foundations (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5-1, 054	B
Concrete: foundations (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5-1, 067	B
Concrete: foundations (accessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5-1, 063	B
Concrete: foundations (accessible)	Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5-1, 066	B
Concrete: foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5-1, 065	B
Concrete: foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Increase in porosity and permeability Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5-1, 067	B
Concrete: foundations (inaccessible)	Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5-1, 043	B, 1
Concrete: foundations (inaccessible)	Structural support	Concrete (reinforced)	Water – flowing	Increase in porosity and permeability Loss of strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5-1, 047	B, 1, 2

Table 3.5.2-18: Overhead Heavy Load Handling Systems – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Crane bridges	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13)	VII.B.A-07	3.3-1, 052	A, 3
Crane bridges and structural members	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Cumulative fatigue damage	TLAA - SLRA Section 4.7.6, "Crane Load Cycle Limits"	VII.B.A-06	3.3-1, 001	A, 3
Crane rails	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13)	VII.B.A-07	3.3-1, 052	A, 3
Rail hardware	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material Loss of preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13)	VII.B.A-730	3.3-1, 199	A, 3
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material Loss of preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13)	VII.B.A-730	3.3-1, 199	A, 3
Structural bolting (Non-NUREG-0612)	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material Loss of preload	Structures Monitoring (B.2.3.33)	VII.B.A-730	3.3-1, 199	B, E, 3
Structural members	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13)	VII.B.A-07	3.3-1, 052	A, 3
Structural members (Non-NUREG-0612)	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	VII.B.A-07	3.3-1, 052	B, E, 3

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.
B. Consistent with component, material, environment, aging effect, and AMP 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. Whereas the NUREG-2191/2192 item calls for a plant-specific AMP, PSL credits an existing AMP based on SLR-ISG-2021-03-STRUCTURES, "Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance".
2. Groundwater is considered to be water-flowing.
3. NUREG-0612 systems are managed by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP; Non-NUREG-0612 Overhead Heavy Load Handling Systems are managed by the Structures Monitoring (B.2.3.33) AMP.

3.6 AGING MANAGEMENT OF ELECTRICAL AND INSTRUMENTATION & 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) AMP[1]:
    - 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
- Switchyard bus and connections
- Transmission conductors and connections
- High-Voltage Insulators
- Metal Enclosed Bus
- Cable Bus
- Uninsulated Ground Conductors

[1] This commodity group is subdivided for technical clarity and proper identification of applicable aging effects consistent with NUREG-2191 guidance.

Table 3.6-1, Summary of Aging Management Evaluations for Electrical and Instrumentation and Control Commodities, provides the aging management reviews and the programs evaluated in NUREG-2191 for electrical and Instrumentation and Control 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

The following table summarizes the results of the AMR for electrical and instrumentation and controls.

Table 3.6.2-1, Electrical and Instrumentation & Control Commodities Summary of Aging Management Evaluation

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 AMPs for electrical and instrumentation and control commodities subject to aging management review. Programs are described in Appendix B. Further details are provided in Table 3.6.2-1.

Materials

The materials of construction for the electrical and instrumentation and control commodities are:

- Aluminum
- Bronze
- Cement
- Copper
- Elastomer
- Galvanized metals
- Insulation material – various organic polymers
- Malleable Iron
- Porcelain
- Polymer (e.g., silicone rubber – for HV insulators)
- Stainless steel
- Steel and steel alloys
- Various metals used for bus and electrical connections

Environment

Electrical and instrumentation and control commodities subject to aging management review are exposed to the following environments.

- Adverse localized environment caused by heat, radiation, contamination, 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 and instrumentation and control 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 AMPs will manage the effects of aging on electrical and instrumentation and control commodities.

- Boric Acid Corrosion (B.2.3.4)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.36)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.3.37)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.38)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.39)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.40)
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.42)
- Environmental Qualification of Electrical Equipment (B.2.2.3)
- High-Voltage Insulators (B.2.3.43)
- Metal Enclosed Bus (B.2.3.41)
- Structures Monitoring (B.2.3.33)

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 PSL evaluation of the areas requiring further evaluation. Programs are described in Appendix B. Italicized text is taken directly from NUREG-2192.

Aging Management Review 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 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 aging management review.

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 on metal enclosed bus (MEB) which is similar in construction to an 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. PSL is currently in the process of replacing all metal enclosed bus (6.9 kV [not within the scope of SLR] and 4.16 kV [within the scope of SLR]) with cable bus (either 750 MCM or 500 MCM medium-voltage power cable). This work began in 2019 and is being performed in a portioned approach, with completion estimated sometime after the submittal of the SLRA. Therefore, cable bus is applicable to the electrical aging management review for PSL. The MV power cable utilized for this commodity group has a Chlorinated Polyethylene (CPE) jacket and EPR insulation.

The in-scope cable bus is routed from the Start-Up Transformers (1A / 1B / 2A / 2B) to the 4.16 kV switchgear (1A2 / 1B2 / 2A2 / 2B2 / 2A4 / 2B4). The cable runs through a ductwork enclosure fabricated of aluminum, with louvered (slotted) bottom panels, and solid sides and top covers. The duct supports are fabricated of steel. The cable bus is run both indoors and outdoors at PSL.

- Loss of Resistance (Insulation Degradation)

The cable bus is routed above ground, in aluminum ductwork, and the cable sections are supported (internal to the duct) by solid epoxy (cycloaliphatic) supports, with holes for the cable to pass through, approximately 6 to 8 feet apart. These feed-through supports have excellent compressive strength and have been in widespread use in electrical bus work since about 1975. The cycloaliphatic epoxy insulators are very similar to porcelain in their ability to resist degradation and are used in millions of medium-voltage power applications throughout various industries. The bottom panels have louvers (slots) in them so that moisture and dirt will not be able to collect in the duct. Each bottom panel has 5 rows of slots, across the width of the panel. For the outside installations, the cable bus will be exposed to weather (ambient temperature and humidity, and the seaside atmosphere), but is shielded from direct sunlight (UV). The cable is jacketed and insulated and has no aging mechanisms in this location. Dirt and debris are not expected to be an issue because the slots in the bottom panel are not large and gravity will generally prevent entry of any dirt beyond minor surface dust. Moisture could enter the duct (via heavy rain), but it will have no impact on the insulated cable bus because it cannot collect in the duct, as it will drain out the slots at the bottom. The cable sections are spliced (with bolted splices and Raychem cover materials) and will not be impacted by dirt/dust, minor debris, or transient moisture (intermittent rain or high humidity).

For the cable bus routed indoors, the ductwork is also routed above ground. The same duct design is utilized, with louvers (slots) in the bottom panels. There is no pathway for moisture to collect in the ductwork, and any dirt that enters the duct will be minor surface dust only. The insulated cables (and cable section splices) will not be impacted by minor surface dust or by the ambient temperature and humidity levels; the air-indoor environment is considered a benign environment for insulated cable (and the aluminum enclosures).

Therefore, there are no aging mechanisms present to cause degradation of the insulated cable bus (in its ductwork installation). The cable bus ductwork itself (and its external supports, and any joints or seals between duct sections) will be addressed by the Structures Monitoring (B.2.3.33) AMP, for any applicable aging management.

- Degradation of Connection / Loss of Torque (Cable Connections)

The cable connections for the in-scope insulated cable bus, at the termination ends of the power cables (at the Start-Up Transformers and at the 4.16 kV switchgear, and any cable connections internal to the cable routing) utilize hardware that includes Belleville (conical) washers, which prevent the degradation of the mechanical connections due to vibration or any potential heat stresses, thereby ensuring a sound electrical connection. Routine plant thermography inspections are performed on medium-voltage electrical terminations (at the transformers and the switchgear) to identify any possible points of increased resistance.

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 (those are addressed separately). Major active equipment assemblies include their associated transmission conductor terminations.

Transmission conductors are subject to aging management review if they are necessary for recovery of offsite power following an SBO event. The PSL power path for restoration of offsite power following an SBO event utilizes line connections of 1081 MCM all aluminum alloy conductor (AAAC) to connect the Unit 1 and Unit 2 230 kV switchyard circuit breakers to the high-voltage station startup transformers on each unit. The Unit 1 and Unit 2 circuit breakers (on switchyard Bays 2 and 4) demarcate the SBO switchyard boundary for SLR. Other PSL transmission conductors (and pathways -such as those through the Unit auxiliary transformers) are not subject to aging management review since they do not perform or support SLR intended functions. The offsite Preferred Power pathway for PSL is through Bay 2 and Bay 4 of the switchyard to the Start-Up Transformers.

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 aging management review if it is necessary for recovery of offsite power following an SBO event. At PSL, switchyard bus from the 230 kV circuit breakers to the high-voltage station startup transformers on each Unit support SBO recovery. Other switchyard bus is not subject to aging management review 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 PSL, the connections between the 230 kV circuit breakers and the high-voltage station startup transformers are made by overhead transmission conductor lines (AAAC). Wind loading that can cause a transmission line and insulators to vibrate or sway are not applicable to the relatively short length of transmission conductor lines utilized at PSL. 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 PSL transmission conductor lines. 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 PSL 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 PSL.

- <u>Loss of Conductor Strength (Corrosion)</u>

This aging effect applies to all aluminum alloy conductor (AAAC) transmission conductors. In-scope transmission conductors at PSL are limited to short length (~800 ft.) transmission line connections of 1081 MCM AAAC cable between the Unit 1 and Unit 2 230 kV circuit breakers and each unit's high-voltage station startup transformer used for recovery of offsite power following an SBO event. The most prevalent mechanism contributing to loss of conductor strength of an AAAC transmission conductor is corrosion, which includes corrosion of the aluminum strand. AAAC transmission conductor is more corrosion resistant than ACSR cable and has a higher strength-to-weight ratio. AAAC cable is better suited for coastal installation due to its superior corrosion resistance. AAAC is also better suited for use in industrial areas. In fact, with respect to corrosion resistance, aluminum is more resistant than steel. Aluminum quickly forms an oxide layer which protects the material underneath and this layer will re-form if damaged (in the absence of environmental stress). A layer of approximately 1 nanometer (10 angstroms) is sufficient to protect the metal underneath. Aluminum is lighter than steel and provides a much higher strength-to-weight ratio. The AAAC conductor therefore is more resistive to corrosion and to loss of conductor strength than the ACSR conductor.

AAAC has a lower resistance than ACSR (with no steel) but has 15 percent-20 percent better conductivity and a longer life than ACSR. Corrosion in AAAC 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, seaside atmospheric conditions, and general meteorological conditions. Air quality in rural areas, such as the area surrounding PSL, generally contains low concentrations of suspended particles and SO_2, which minimize the corrosion rate. There are no major industries within the immediate vicinity of PSL.

The PSL site is located on Hutchinson Island, on the Atlantic coast of Florida. The Atlantic Ocean borders the east side of the site, and the Indian River (a tidal lagoon) borders the west side of the site. The closest industrial facility to the site is a St. Lucie County waste water plant, about 2 miles to the south. The PSL site is about halfway between Ft. Pierce (to the north) and Stuart (to the south). The area around the site is primarily devoted to residential use, sand mining, light agriculture, and wetlands.

Regarding the loss of strength of transmission conductors, tests performed by Ontario Hydroelectric showed a 30% 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 subsequent period of extended operation.

The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60% of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind, and temperature. These requirements are reviewed concerning the specific conductors included in the aging management review.

PSL utilizes a 37-strand 1081 MCM AAAC conductor (diameter 1.196 in.) for the overhead lines from the switchyard circuit breakers to the startup transformers. The NESC maximum design loading for the AAAC conductor is 16,000 lbs. The ultimate strength for the 1081 MCM AAAC line is 35,150 lbs. The Ontario Hydroelectric study showed a 30% loss of composite conductor strength in an 80-year old conductor. In the case of the 37-strand AAAC transmission conductors, a 30% of ultimate strength would mean that there still is a 53% margin between the age-reduced ultimate strength (24,605 lbs.) and the NESC required limit of 16,000 lbs.

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 PSL.

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, copper, and aluminum alloy components in the PSL 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 PSL, 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 OE, this method of installation has proven to provide a corrosion-resistant low electrical resistance connection. In addition, PSL periodically performs infrared inspections of the 230 kV switchyard connections to verify the integrity of the connections. The infrared inspections of the 230 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 PSL.

Therefore, increased connection resistance due to general corrosion resulting from oxidation of switchyard connection metal surfaces is not an aging effect requiring management at PSL.

<u>*Increased Resistance of Connection (Loss of Preload)*</u>

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 PSL are limited to the transmission line connections between the 230 kV circuit breakers and each unit's high-voltage station startup transformer used for recovery of offsite power following an SBO event. Routine inspections of the PSL 230 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 PSL.

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 PSL.

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 PSL 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 subsequent license renewal are discussed in Appendix B.1.3, Quality Assurance Program and Administrative Controls.

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 OE process and acceptance criteria (for PSL) are described in Appendix B.

3.6.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the electrical and instrumentation and control commodities:

- Section 4.4, “Environmental Qualification (EQ) of Electrical Equipment”

3.6.3 Conclusion

Electrical and instrumentation and control commodities that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.21(a)(1). AMPs selected to manage aging effects for electrical and instrumentation and control commodities are identified in Section 3.6.2.1 and in the following tables.

A description of AMPs is provided in Appendix B, along with the demonstration that the identified aging effects will be effectively managed for the SPEO.

Based on the demonstrations provided in Appendix B, the effects of aging associated with electrical and instrumentation and control commodities will be managed such that there is reasonable assurance the intended functions will be maintained consistent with the CLB during the SPEO.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical and Instrumentation & Control Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs (AMP)/TLAA	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 subsequent period of extended operation. 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,(SRP-SLR Section 3.6.2.2.1)	Consistent with NUREG-2191. EQ equipment is not subject to aging management review 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, toughened glass; polymers; silicone rubber; fiberglass, aluminum alloy exposed to air – outdoor	Loss of material on metallic connectors 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 AMP will manage these aging effects.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical and Instrumentation & Control Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 003	High-voltage insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers; silicone rubber; fiberglass, aluminum alloy exposed to air – outdoor	Reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume or industrial effluent contamination; peeling of silicone rubber sleeves for polymer insulators; or degradation of glazing on porcelain insulators	AMP XI.E7, "High-Voltage Insulators"	No	Consistent with NUREG-2191. The High-Voltage Insulators AMP will manage these aging effects.
3.6-1, 004	Transmission conductors composed of aluminum; exposed to air – outdoor	Loss of conductor strength due to corrosion	A plant-specific AMP is to be evaluated (for AAAC)	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to PSL. See Section 3.6.2.2.3 for further evaluation.
3.6-1, 005	Transmission connectors composed of aluminum; exposed to air – outdoor	Increased resistance of connection due to oxidation or loss of pre-load	A plant-specific AMP is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to PSL. See Section 3.6.2.2.3 for further evaluation.
3.6-1, 006	Switchyard bus and connections composed of copper and bronze; with aluminum hardware 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 AMP is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to PSL. See Section 3.6.2.2.3 for further evaluation.
3.6-1, 007	Transmission conductors composed of aluminum; exposed to air – outdoor	Loss of material due to wind-induced abrasion	A plant-specific AMP is to be evaluated for AAAC	Yes (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to PSL. See Section 3.6.2.2.3 for further evaluation.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical and Instrumentation & Control Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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 Environmental Qualification Requirements AMP will manage the effects of aging. PSL electrical penetration assemblies within the scope of SLR are covered by the Environmental Qualification Program.
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 Environmental Qualification Requirements Used in Instrumentation Circuits AMP will manage these aging effects. This AMP includes review of calibration results or surveillance findings for instrumentation circuits.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical and Instrumentation & Control Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs (AMP)/TLAA	Further Evaluation Recommended	Discussion
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 Environmental Qualification Requirements XI.E3A (B.2.3.38) AMP, the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements XI.E3B (B.2.3.40) AMP, or the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements XI.E3C (B.2.3.40) AMP will manage these aging effects. AMPs include inspection of manholes, verification of sump pump function, and de-watering activities as required.
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.2.3.41) AMP or Structures Monitoring (B.2.3.33) AMP will manage these aging effects.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical and Instrumentation & Control Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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.2.3.41) 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.2.3.41) 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.2.3.41) AMP or Structures Monitoring (B.2.3.33) AMP will manage these aging effects.
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.2.3.41) AMP or Structures Monitoring (B.2.3.33) AMP will manage these aging effects.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical and Instrumentation & Control Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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 AMP 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	Pursuant to the discussion in SLRA Section 2.5.1.3, the fuse holders within the scope of SLR are in an air-indoor controlled environment and do not experience the detailed environmental aging effects.
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 AMP 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	Pursuant to the discussion in SLRA Section 2.5.1.3, the fuse holders within the scope of SLR are not subject to ohmic heating, thermal cycling, or electrical transients.
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 AMP 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	Pursuant to the discussion in SLRA Section 2.5.1.3, the fuse holders within the scope of SLR are not subject to frequent manipulation and will not experience fatigue degradation (at the metallic clamp).

Table 3.6-1: Summary of Aging Management Evaluations for Electrical and Instrumentation & Control Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs (AMP)/TLAA**	**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 Environmental Qualification Requirements 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 AAAC	No	NUREG-2191 aging effects are not applicable to PSL. See Section 3.6.2.2.3 for further evaluation.
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 AMP 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	Pursuant to the discussion in SLRA Section 2.5.1.3, the fuse holders within the scope of SLR are located in an air-indoor controlled environment and are not subject to the detailed environmental aging effects.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical and Instrumentation & Control Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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, 025	There is no 3.6-1, 025 in NUREG-2192.				
3.6-1, 026	There is no 3.6-1, 026 in NUREG-2192.				
3.6-1, 027	Cable bus: external surface of enclosure assemblies galvanized steel; aluminum; air – indoor controlled or uncontrolled	None	None	No	Consistent with NUREG-2191 (for bus enclosures in air indoor – controlled or air indoor – uncontrolled environments.
3.6-1, 028	There is no 3.6-1, 028 in NUREG-2192.				
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 AMP is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	As addressed in the “Further Evaluation Items” discussion, Section 3.6.2.2.2, there are no applicable aging effects for the cable bus.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical and Instrumentation & Control Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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	AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.6.2.2.2)	As addressed in the “Further Evaluation Items” discussion, Section 3.6.2.2.2, the Structures Monitoring (B.2.3.33) AMP evaluates/addresses the aging effects for the cable bus steel external enclosures (and the duct supports) at PSL, for both air – indoor and air – outdoor environments. The cable bus enclosure assemblies are fabricated of aluminum.
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	AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.6.2.2.2)	As addressed in the “Further Evaluation Items” discussion, Section 3.6.2.2.2, the Structures Monitoring (B.2.3.33) AMP evaluates/addresses the aging effects for the cable bus steel external enclosures (and the duct supports) at PSL, for both air – indoor and air – outdoor environments. The cable bus enclosure assemblies are fabricated from aluminum.
3.6-1, 032	Cable bus: external surface of enclosure assemblies: composed of steel; air – indoor controlled	None	None	No	Not applicable.

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program (AMP) / TLAA	NUREG-2191 Item	Table 1 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 CFR50.49 Environmental Qualification Requirements (B.2.3.42)	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.2.3.39)	VI.A.LP-35b	3.6-1, 010	A
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.2.3.40)	VI.A.LP-35c	3.6-1, 010	A

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program (AMP) / TLAA	NUREG-2191 Item	Table 1 Item	Notes
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.2.3.38)	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
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.2.3.36)	VI.A.LP-33	3.6-1, 008	A

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program (AMP) / TLAA	NUREG-2191 Item	Table 1 Item	Notes
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.2.3.37)	VI.A.LP-34	3.6-1, 009	A
High-voltage electrical insulators	Insulate (electrical)	Porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers silicone rubber; fiberglass, aluminum alloy	Air – outdoor	Loss of Material due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind	High-Voltage Insulators (B.2.3.43)	VI.A.LP-32	3.6-1, 002	A

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation								
Structure and/or Component	**Component Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program (AMP) / TLAA**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
High-voltage electrical insulators	Insulate (electrical)	Porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers silicone rubber; fiberglass, aluminum alloy	Air – outdoor	Reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume or industrial effluent contamination; peeling of silicone rubber sleeves for polymer insulators; or glazing degradation for porcelain insulators	High-Voltage Insulators (B.2.3.43)	VI.A.LP-28	3.6-1, 003	A
Switchyard bus and connections	Electrical Continuity	Copper; bronze; stainless steel; galvanized steel; aluminum	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 connectors	Electrical Continuity	Aluminum	Air – outdoor	None	None	VI.A.LP-48	3.6-1, 005	I
Transmission conductors	Electrical Continuity	Aluminum	Air – outdoor	None	None	VI.A.LP-38	3.6-1, 004	I

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program (AMP) / TLAA	NUREG-2191 Item	Table 1 Item	Notes
Transmission conductors	Electrical Continuity	Aluminum	Air – outdoor	None	None	VI.A.LP-47	3.6-1, 007	I
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 aging mechanisms in accordance with 10 CFR 50.49	Environmental Qualification of Electric Equipment (B.2.2.3)	VI.B.L-05	3.6-1, 001	A

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program (AMP) / TLAA	NUREG-2191 Item	Table 1 Item	Notes
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 aging mechanisms in accordance with 10 CFR 50.49	Environmental Qualification of Electric Equipment (B.2.2.3)	VI.B.L-05	3.6-1, 001	A
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.2.3.41)	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.2.3.41) or Structures Monitoring (B.2.3.33)	VI.A.LP-29	3.6-1, 011	E
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	E

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation								
Structure and/or Component	**Component Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program (AMP) / TLAA**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Metal enclosed bus: external surface of enclosure assemblies	Electrical Continuity	Galvanized steel; aluminum	Air – outdoor	Loss of material	Metal Enclosed Bus (B.2.3.41) or Structures Monitoring (B.2.3.33)	VI.A.LP-42	3.6-1, 015	E
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.2.3.41) or Structures Monitoring (B.2.3.33)	VI.A.LP-43	3.6-1, 014	A
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.2.3.33)	VI.A.LP-26	3.6-1, 013	A
Cable Bus: external surface of enclosure assemblies	Electrical Continuity	Galvanized steel; aluminum	Air – indoor controlled	None	None	VI.A.L-09	3.6.1, 027	I
Cable Bus: Cable bus: electrical insulation	Insulate (electrical)	Electrical insulation; insulators	Air – indoor controlled or uncontrolled Air - outdoor	None	None	VI.A.L-11	3.6-1, 029	I
Cable Bus: Cable bus: external surface of enclosure assemblies	Electrical Continuity	Galvanized steel; aluminum	Air – indoor uncontrolled Air- outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.S.6, Structures Monitoring (B.2.3.33)	VI.A.L.13	3.6.1, 031	A

General Notes

A. Consistent with component, 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.
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 PSL 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 PSL letter L-2021-142, 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 PSL 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 PSL Units 1 and 2 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:

- PSL Units 1 and 2 Updated Final Safety Analysis Report (UFSARs)

- PSL Units 1 and 2 Technical Specifications and Bases
- PSL Units 1 and 2 Technical Requirements Manual
- NRC Safety Evaluation Reports (SERs) for the original operating license
- Subsequent NRC Safety Evaluations (SEs)
- Docketed licensing correspondence between previous PSL owners/operators, FPL, 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 PSL 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 PSL. 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 PSL Units 1 and 2 Updated Final Safety Analysis Reports (UFSARs) 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. Based on this review, there are two currently active 10 CFR 50.12 exemption requests, one for PSL Unit 1 and one for PSL Unit 2, that relate to a time sensitive TLAA topic. 10 CFR 54.21(c)(2) requires the subsequent license renewal application to include an identification and justification for continuation of any TLAA-related exemptions issued in accordance with 10 CFR 50.12.

The TLAA-related exemptions are the same for PSL Units 1 and 2 in that they request an exemption from the requirements of 10 CFR 50, Appendix G, to use the methodology of Topical Report CE NPSD-683-A, Rev 06, "Development of a RCS Pressure and Temperature Limits Report for the Removal of P-T Limits and LTOP Requirements from the Technical Specifications," (Reference ML011350387) for the generation of the current P-T limits for the PSL Units 1 and 2 reactor coolant pressure boundary during normal operating and hydrostatic or leak rate testing conditions. Specifically, use of the topical report methodology requires an exemption from the requirements of 10 CFR Part 50, Appendix G, Section IV.A.2, "Pressure-Temperature Limits and Minimum Temperature Requirements." These exemptions were approved by the NRC in letters dated December 6, 2011 (Reference ML11297A096) and April 30, 2012 (Reference ML12096A270) for PSL Units 1 and 2, respectively. The evaluation of these TLAA-related exemptions for the 80-year SPEO is included in Section 4.2.5.

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, Table 4.7-1, list the example TLAAs provided in NUREG-2192 and specify whether they have been identified as TLAAs for PSL. 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 - PSL 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 TLAA Listed in NUREG-2192, Table 4.1-2

NUREG-2192, Table 4.1-2 - Generic TLAA		Applies to PSL	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 4.2.5
	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	4.3.2
	Environmentally-Assisted Fatigue	Yes	4.3.3
	High-Energy Line Break Analyses (Unit 2 only)	Yes	4.3.4
	Cycle-dependent Fracture Mechanics or Flaw Evaluations	Yes	4.7.8
	Cycle-dependent Fatigue Waivers	No	N/A
Environmental Qualification of Electrical Equipment		Yes	4.4
Concrete Containment Tendon Prestress		No	4.5
Containment Liner Plate, Metal Containments, and Penetrations Fatigue		Yes	4.6

Table 4.1.5-2
Review of Plant-Specific TLAA Listed in NUREG-2192, Table 4.7-1

NUREG-2192, Table 4.7-1 Examples of Potential Plant-Specific TLAA Topics	Applies to PSL	SLRA Section
PWRs		
Reactor pressure vessel underclad cracking	No (Note 1)	N/A
Leak-before-break	Yes	4.7.1
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”	No (Note 2)	N/A
EPRI MRP cycle-based and fluence based analyses in support of MRP-227	No (Note 3)	N/A
BWRs and PWRs		
Fatigue of cranes (crane cycle limits)	Yes	4.7.6
Fatigue of the spent fuel pool liner	No (Note 4)	N/A
Corrosion allowance calculations	No Note 5)	N/A
Flaw growth due to stress corrosion cracking	No (Note 6)	N/A
Predicted lower limit	No	4.5

Note 1: Refer to SLRA Section 3.1.2.2.5.

Note 2: As discussed in Section 4.3.2 of NUREG-1779 and in the response to NRC RAI 4.3-2 (Reference ML022890457), the review of PSL CLB documentation and correspondence regarding NRC Bulletin 88-08 identified no calculations that meet the definition of a TLAA as defined in 10 CFR 54.3. This conclusion remains valid for the 80-year SPEO.

Note 3: Cycle-based fatigue for the PSL Units 1 and 2 RVI is included with the generic industry TLAA “Metal Fatigue of Class 1 Components” in Section 4.3.1. A PSL Units 1 and 2 plant-specific RVI fluence-based analysis is not part of the PSL CLB and therefore does not meet the TLAA definition for SLR.

Note 4: There is no spent fuel pool liner fatigue analysis included in either the PSL Unit 1 or 2 CLB.

Note 5: No time limited metal corrosion allowance analyses for PSL Units 1 and 2 were identified.

Note 6: No time limited flaw growth due to stress corrosion analyses for PSL Units 1 and 2 were identified.

Table 4.1.5-3
Summary of Results – PSL 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 and 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	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.3.1
Metal Fatigue of Non-Class 1 Components	(i) remains valid for the SPEO, and (ii) projected to the end of the SPEO	4.3.2
Environmentally-Assisted Fatigue	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.3.3
High-Energy Line Break Analyses (Unit 2 only)	(i) remains valid for the SPEO, and (iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.3.4
ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRIC EQUIPMENT	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.4
CONCRETE CONTAINMENT TENDON PRESTRESS	Not applicable	4.5

Table 4.1.5-3
Summary of Results – PSL TLAAs

TLAA Description	Resolution 10 CFR 54.21(c)(1) Section	Section
CONTAINMENT LINER PLATE, METAL CONTAINMENTS AND PENETRATIONS FATIGUE	(i) remains valid for the SPEO	4.6
OTHER PLANT-SPECIFIC TLAA		4.7
Leak-Before-Break of Reactor Coolant System Loop Piping	(ii) projected to the end of the SPEO	4.7.1
Alloy 600 Instrument Nozzle Repairs	(i) remains valid for the SPEO	4.7.2
Unit 1 Core Support Barrel Repairs	(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
Flaw Tolerance Evaluation for CASS RCS Piping Components	(ii) projected to the end of the SPEO	4.7.7
Unit 2 Structural Weld Overlay PWSCC Crack Growth Analyses	(iii) the effects of aging on the intended function will be adequately managed for the SPEO	4.7.8

4.2 REACTOR VESSEL NEUTRON EMBRITTLEMENT ANALYSIS

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 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 PSL 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 PSL 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 1.0×10^{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 is a TLAA for the PSL Units 1 and 2 80-year SPEO.

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. PSL 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.

The projected 80-year EFPY for both PSL Units 1 and 2 is 72 EFPY.

Fluence Projections

Updated neutron fluence calculations for PSL Units 1 and 2 were performed and documented in Westinghouse Report WCAP-18609-NP (Reference 4.8.1). The PSL neutron transport methodology used to generate the data followed the guidance of Regulatory Guide (RG) 1.190, and is consistent with the NRC approved methodology described in Westinghouse Report WCAP-18124-NP-A. Updated neutron fluence calculations were used as an input to the RPV integrity evaluations in support of the SPEO.

Discrete ordinates transport calculations were performed on a fuel-cycle-specific basis to determine the neutron and gamma ray environment within the reactor geometry. 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.

Top views of the model geometry at the core midplane for PSL Unit 1 with (applicable to PSL Unit 1, Cycles 1–5) and without (applicable to PSL Unit 1, Cycle 6 and beyond) a fully circumferential thermal shield are shown in Figure 2.4-1 and Figure 2.4-4 of Reference 4.8.1, respectively. A top view of the model geometry at the core midplane for PSL Unit 2 is shown in Figure 2.5-1 of Reference 4.8.1. In these figures, a single quadrant is depicted showing the arrangement of the core, reactor internals, core barrel, downcomer, RPV cladding, RPV, reactor cavity, reflective insulation, RPV support structure, and bioshield. Depictions of the in-vessel surveillance capsules, including their associated support structures, are also shown.

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.

The uncertainty associated with the calculated neutron exposure of the PSL Units 1 and 2 surveillance capsule and reactor pressure vessel beltline is based on the recommended approach provided in RG 1.190. In particular, the qualification of the methodology was carried out in the following four stages:

1. Simulator Benchmark Comparisons: Comparisons of calculations with measurements from simulator benchmarks, including the pool critical assembly (PCA) simulator at the Oak Ridge National Laboratory (ORNL) and the VENUS-1 Experiment.
2. Operating Reactor and Calculational Benchmarks: Comparisons of calculations with surveillance capsule and reactor cavity measurements from the H.B. Robinson power reactor benchmark experiment. Also considered are comparisons of calculations to results published in the NRC fluence calculation benchmark.
3. Analytic Uncertainty Analysis: An analytical sensitivity study addressing the uncertainty components resulting from important input parameters applicable to the plant-specific transport calculations used in the neutron exposure assessments.
4. Plant-Specific Benchmarking: Comparisons of the plant-specific calculations with all available dosimetry results from the PSL surveillance program.

The first phase of the methods qualification (simulator benchmark comparisons) addressed the adequacy of basic transport calculation and dosimetry evaluation techniques and associated cross-sections. This phase, however, did not test the accuracy of commercial core neutron source calculations nor did it address uncertainties in operational or geometric variables that impact power reactor calculations. The second phase of the qualification (operating reactor and calculational benchmark comparisons) addressed uncertainties in these additional areas that are primarily methods-related and would tend to apply generically to all fast neutron exposure evaluations. The third phase of the qualification (analytical sensitivity study) identified the potential uncertainties introduced into the overall evaluation due to calculational methods approximations, as well as to a lack of knowledge relative to various plant-specific input parameters. The overall calculational uncertainty applicable to the PSL Units 1 and 2 analyses were established from results of these three phases of the methods qualification and is presented in Reference 4.8.1.

The fourth phase of the uncertainty assessment (comparisons with PSL Units 1 and 2 measurements) was used solely to demonstrate the validity of the transport calculations and to confirm the uncertainty estimates associated with the analytical results. The comparison was used only as a check and was not used in any way to modify the calculated surveillance capsule and pressure vessel neutron exposures. The validation of the analytical model based on the measured plant dosimetry is provided in Appendix A of Reference 4.8.1.

Exposure Results

Tables 4.2.1-1 and 4.2.1-2 summarize the results of the fluence projections to 72 EFPY for PSL Units 1 and 2 RPV materials, respectively. Tables 4.2.1-1 and Table 4.2.1-2 assume a 10 percent positive bias on the peripheral and re-entrant corner assembly relative powers. These neutron exposure data are the maximum values 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., outlet 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), in accordance with 10 CFR 54.21(c)(1)(iii). The exposure results are used as inputs in the neutron embrittlement TLAA evaluations in the remainder of Section 4.2.1.

Table 4.2.1-1
St. Lucie Unit 1 Fast Neutron Fluence (E > 1.0 MeV) at RPV Welds and Shells

Projections with a +10% bias on the peripheral and re-entrant corner assembly relative powers	
Material	**Fast Neutron (E > 1.0 MeV) Fluence (n/cm^2)**
	72 EFPY
Inlet (Cold Leg)-Nozzle-to-Upper-Shell Weld (lowest extent)	7.24E+16
Outlet (Hot Leg)-Nozzle-to-Upper-Shell Weld (lowest extent)	8.44E+16
Upper Shell	3.01E+18
Upper-to-Intermediate-Shell Circumferential Weld	3.77E+18
Intermediate Shell	6.38E+19
Intermediate Shell Longitudinal Weld – 15°	3.91E+19
Intermediate Shell Longitudinal Weld – 135°	2.82E+19
Intermediate Shell Longitudinal Weld – 255°	3.78E+19
Intermediate-to-Lower-Shell Circumferential Weld	6.32E+19
Lower Shell	6.35E+19
Lower Shell Longitudinal Weld – 15°	3.88E+19
Lower Shell Longitudinal Weld – 135°	2.80E+19
Lower Shell Longitudinal Weld – 255°	3.76E+19
Lower-Shell-to-Bottom-Head Circumferential Weld	4.53E+16

Table 4.2.1-2
St. Lucie Unit 2 Fast Neutron Fluence (E > 1.0 MeV) at RPV Welds and Shells

Projections with a +10% bias on the peripheral and re-entrant corner assembly relative powers	
Material	**Fast Neutron (E > 1.0 MeV) Fluence (n/cm^2)**
	72 EFPY
Inlet (Cold Leg)-Nozzle-to-Upper-Shell Weld (lowest extent)	7.54E+16
Outlet (Hot Leg)-Nozzle-to-Upper-Shell Weld (lowest extent)	1.03E+17
Upper Shell[(a)]	1.52E+18
Upper-to-Intermediate-Shell Circumferential Weld	1.75E+18
Intermediate Shell	6.56E+19
Intermediate Shell Longitudinal Weld – 15°	4.31E+19
Intermediate Shell Longitudinal Weld – 135°	3.22E+19
Intermediate Shell Longitudinal Weld – 255°[(b)]	4.31E+19
Intermediate-to-Lower-Shell Circumferential Weld	6.52E+19
Lower Shell	6.53E+19
Lower Shell Longitudinal Weld – 15°	4.29E+19
Lower Shell Longitudinal Weld – 135°	3.20E+19
Lower Shell Longitudinal Weld – 255°[(b)]	4.29E+19
Lower-Shell-to-Bottom-Head Circumferential Weld	6.32E+16

Notes:

(a) Exposure values for the upper shell longitudinal welds are bounded by the exposure values for the upper shell.

(b) Exposure values for the intermediate shell and lower shell 255° longitudinal welds are bounded by the exposure values for the intermediate shell and lower shell 15° longitudinal welds.

4.2.2 Pressurized Thermal Shock

TLAA Description

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 (Reference 4.8.2), provides protection against PTS events. It establishes screening criteria on PWR vessel embrittlement, as measured by the maximum reference nil-ductility transition temperature in the limiting beltline component at the end of license, termed RT_{PTS}. RT_{PTS} screening values are set for beltline axial welds, forgings or plates, and for beltline circumferential weld seams for plant operation to the end-of-plant license. Calculating the reference temperature for pressurized thermal shock (RT_{PTS}) values is consistent with the methods given in Regulatory Guide 1.99 (Reference 4.8.3).

The current PTS analyses, evaluated for fluence values predicted for 60 years of operation for PSL Units 1 and 2, are TLAAs requiring evaluation for the 80-year SPEO since a change in the operating license term of the facility is being requested.

TLAA Evaluation

The accepted methods of 10 CFR 50.61 were used with the maximum fluence values from Tables 4.2.1-1 and 4.2.1-2 for PSL Units 1 and 2, respectively, to calculate the following RT_{PTS} values for the RPV materials for each unit at 72 EFPY. The RT_{PTS} calculations for SPEO are summarized in Tables 4.2.2-1 and 4.2.2-2 for PSL Units 1 and 2, respectively. All of the beltline reactor vessel materials for PSL Units 1 and 2 are projected to remain below the RT_{PTS} screening criteria values of 270ºF for plates, forgings, and longitudinal welds, and 300ºF for circumferentially-oriented welds.

The PSL Unit 1 limiting RT_{PTS} value for base metal or longitudinal weld materials at 72 EFPY is 250.8°F, which corresponds to lower shell axial weld seams 3-203 A, B, & C (Heat # 305424). The PSL Unit 1 limiting RT_{PTS} value for circumferentially-oriented weld materials at 72 EFPY is 135.3°F, which corresponds to the upper to intermediate shell girth weld seam 8-203 (Heat # 21935). The intermediate to lower shell girth weld seam 9-203 (Heat # 90136) result without the use of surveillance data is higher; however, use of credible surveillance data makes this material non-limiting.

The PSL Unit 2 limiting RT_{PTS} value for base metal or longitudinal weld materials at 72 EFPY is 195.3°F, which corresponds to intermediate shell plate M-605-1 with credible surveillance data. The PSL Unit 2 limiting RT_{PTS} value for circumferentially-oriented weld materials at 72 EFPY is 64.1°F, which corresponds to the intermediate to lower shell girth weld seam 101-171 (Heat #'s 83637 / 3P7317).

The PSL Units 1 and 2 RPV 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 in accordance with 10 CFR 54.21(c)(1)(ii).

Table 4.2.2-1 RT_{PTS} Calculations for St. Lucie Unit 1 Reactor Vessel Beltline Materials

Material	CF[(a)]	Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	FF[(c)]	RTNDT(U)[(d)] (°F)	Predicted ΔRT_{NDT} (°F)	σU (°F)	σΔ[(e)] (°F)	M (°F)	RTPTS (°F)
Beltline									
Intermediate Shell Plate C-7-1	74.60	6.38	1.447	0	108.0	0	17.0	34.0	142.0
Intermediate Shell Plate C-7-2	74.60	6.38	1.447	-10	108.0	0	17.0	34.0	132.0
Intermediate Shell Plate C-7-3	73.80	6.38	1.447	10	106.8	0	17.0	34.0	150.8
Lower Shell Plate C-8-1	107.80	6.35	1.447	20	155.9	0	17.0	34.0	209.9
with credible surveillance data[(f)]	81.84	6.35	1.447	20	118.4	0	8.5	17.0	155.4
Lower Shell Plate C-8-2	108.35	6.35	1.447	20	156.7	0	17.0	34.0	210.7
with credible surveillance data[(f)]	82.67	6.35	1.447	20	119.6	0	8.5	17.0	156.6
Lower Shell Plate C-8-3	82.60	6.35	1.447	0	119.5	0	17.0	34.0	153.5
with credible surveillance data[(f)]	62.83	6.35	1.447	0	90.9	0	8.5	17.0	107.9
Intermediate to Lower Shell Girth Weld Seam 9-203 (Heat # 90136)	124.25	6.32	1.446	-60	179.6	0	28.0	56.0	175.6
with credible surveillance data[(f)]	85.79	6.32	1.446	-60	124.0	0	14.0	28.0	92.0
Intermediate Shell Axial Weld Seams 2-203 A, B, & C (Heat #'s 34B009 / A-8746)	90.65	3.91	1.351	-56	122.5	17	28.0	65.5	132.0
Lower Shell Axial Weld Seams 3-203 A, B, & C (Heat # 305424)	188.80	3.88	1.350	-60	254.8	0	28.0	56.0	250.8
with non-credible Beaver Valley Unit 1 surveillance data[(f)]	176.28	3.88	1.350	-60	237.9	0	28.0	56.0	233.9
Extended Beltline									
Upper Shell Plate C-6-1	113.10	0.301	0.671	33	75.9	0	17.0	34.0	142.9
Upper Shell Plate C-6-2	113.10	0.301	0.671	15	75.9	0	17.0	34.0	124.9
Upper Shell Plate C-6-3	113.10	0.301	0.671	15	75.9	0	17.0	34.0	124.9
Upper to Intermediate Shell Girth Weld Seam 8-203 (Heat # 21935)	172.22	0.377	0.730	-56	125.8	17	28.0	65.5	135.3
Upper Shell Axial Seams 1-203 A, B, and C (Heat #'s 21935 / 12008)	208.62	0.377	0.730	-50	152.3	0	28.0	56.0	158.3

Notes:

(a) Chemistry factors (CFs) are taken from Table 5-4 of Reference 4.8.1.

(b) The 72 EFPY maximum fluence values for the reactor vessel materials were taken from Table 2.4-5 of Reference 4.8.1. Only those projected fluence values with a 1.1 bias on the peripheral and re-entrant corner assembly relative powers are considered.

(c) FF = fluence factor = $f^{(0.28 - 0.10 * \log(f))}$.

(d) $RT_{NDT(U)}$ values taken from Table 3-1 of Reference 4.8.1.

(e) Per 10 CFR 50.61, the base metal σ_Δ = 17°F when surveillance data is non-credible or not used to determine the CF, and the base metal σ_Δ = 8.5°F when credible surveillance data is used to determine the CF. Also, per 10 CFR 50.61, the weld metal σ_Δ = 28°F when surveillance data are non-credible or not used to determine the CF, and the weld metal σ_Δ = 14°F when credible surveillance data are used to determine the CF. However, σ_Δ need not exceed 0.5 * ΔRT_{NDT}.

(f) The credibility evaluation for the St. Lucie Unit 1 surveillance data in Appendix B of Reference 4.8.1 determined that the St. Lucie Unit 1 surveillance data for the Lower Shell Plate C-8-2 and Heat # 90136 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. The Beaver Valley Unit 1 Heat # 305424 surveillance weld was determined to be non-credible in WCAP-18102-NP (Reference 4.8.4).

Table 4.2.2-2 RT_{PTS} Calculations for St. Lucie Unit 2 Reactor Vessel Beltline Materials

Material	CF[(a)]	Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	FF[(c)]	$RT_{NDT(U)}$[(d)] (°F)	Predicted ΔRT_{NDT} (°F)	σU (°F)	σΔ[(e)] (°F)	M (°F)	RT_{PTS} (°F)
Beltline									
Intermediate Shell Plate M-605-1	74.15	6.56	1.452	30	107.7	0	17.0	34.0	171.7
with **credible** surveillance data[(f)]	102.12	6.56	1.452	30	148.3	0	8.5	17.0	195.3
Intermediate Shell Plate M-605-2	91.50	6.56	1.452	10	132.9	0	17.0	34.0	176.9
Intermediate Shell Plate M-605-3	74.15	6.56	1.452	0	107.7	0	17.0	34.0	141.7
with **credible** surveillance data[(f)]	102.12	6.56	1.452	0	148.3	0	8.5	17.0	165.3
Lower Shell Plate M-4116-1	37.00	6.53	1.451	20	53.7	0	17.0	34.0	107.7
Lower Shell Plate M-4116-2	44.00	6.53	1.451	20	63.9	0	17.0	34.0	117.9
Lower Shell Plate M-4116-3	44.00	6.53	1.451	20	63.9	0	17.0	34.0	117.9
Intermediate to Lower Shell Girth Weld Seam 101-171 (Heat #'s 83637 / 3P7317)	40.05	6.52	1.451	-50	58.1	0	28.0	56.0	64.1
Intermediate Shell Axial Weld Seams 101-124A, B, & C (Heat # 83642)	36.35	4.31	1.372	-56	49.9	17	24.9	60.4	54.2
Intermediate Shell Axial Weld Seam 101-124C Repair (Heat # 83637)	34.05	4.31	1.372	-50	46.7	0	23.4	46.7	43.4
with **credible** surveillance data[(f)]	23.55	4.31	1.372	-50	32.3	0	14.0	28.0	10.3
Lower Shell Axial Welds Seams 101-142A, B, & C (Heat # 83637)	34.05	4.29	1.371	-50	46.7	0	23.3	46.7	43.4
with **credible** surveillance data[(f)]	23.55	4.29	1.371	-50	32.3	0	14.0	28.0	10.3

Table 4.2.2-2 RT_{PTS} Calculations for St. Lucie Unit 2 Reactor Vessel Beltline Materials (Continued)

Material	CF[(a)]	Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	FF[(c)]	$RT_{NDT(U)}$[(d)] (°F)	Predicted ΔRT_{NDT} (°F)	σU (°F)	σΔ[(e)] (°F)	M (°F)	RT_{PTS} (°F)
Extended Beltline									
Upper Shell Plate M-604-1	118.00	0.152	0.506	50	59.7	0	17.0	34.0	143.7
Upper Shell Plate M-604-2	118.25	0.152	0.506	50	59.8	0	17.0	34.0	143.8
Upper Shell Plate M-604-3	116.60	0.152	0.506	10	59.0	0	17.0	34.0	103.0
Upper to Intermediate Shell Girth Weld Seam 106-121 (Heat # 83637)	34.05	0.175	0.538	-50	18.3	0	9.2	18.3	-13.4
with **credible** surveillance data[(f)]	23.55	0.175	0.538	-50	12.7	0	6.3	12.7	-24.7
Upper Shell Axial Weld Seams 101-122A & C (Heat # 5P5622)	74.13	0.175	0.538	-40	39.9	0	19.9	39.9	39.8
Upper Shell Axial Weld Seams 101-122A & C (Heat # 2P5755)	96.64	0.175	0.538	-50	52.0	0	26.0	52.0	54.0
Upper Shell Axial Weld Seam 101-122B (Heat # 5P5622)	74.13	0.175	0.538	-40	39.9	0	19.9	39.9	39.8
Hot Leg Nozzle A M-4103-2	89.92	0.0103	0.112	-30	10.1	0	5.0	10.1	-9.9
Hot Leg Nozzle B M-4103-1	90.36	0.0103	0.112	-20	10.1	0	5.1	10.1	0.2
Hot Leg Nozzle to Shell Weld Seam 105-121A (Heat # 4P6519)	63.70	0.0103	0.112	-60	7.1	0	3.6	7.1	-45.7
Hot Leg Nozzle to Shell Weld Seam 105-121B (Various SMAWs)	68.00	0.0103	0.112	-60	7.6	0	3.8	7.6	-44.8

Notes:

(a) Chemistry factors (CFs) are taken from Table 5-5 of Reference 4.8.1.

(b) The 72 EFPY maximum fluence values for the reactor vessel materials were taken from Table 2.5-5 of Reference 4.8.1. Only those projected fluence values with a 1.1 bias on the peripheral and re-entrant corner assembly relative powers are considered.

(c) FF = fluence factor = $f^{(0.28 - 0.10 * \log (f))}$.

(d) $RT_{NDT(U)}$ values taken from Table 3-2 of Reference 4.8.1.

(e) Per 10 CFR 50.61, the base metal σ_Δ = 17°F when surveillance data is non-credible or not used to determine the CF, and the base metal σ_Δ = 8.5°F when credible surveillance data is used to determine the CF. Also, per 10 CFR 50.61, the weld metal σ_Δ = 28°F when surveillance data are non-credible or not used to determine the CF, and the weld metal σ_Δ = 14°F when credible surveillance data are used to determine the CF. However, σ_Δ need not exceed 0.5 * ΔRT_{NDT}.

(f) The credibility evaluation for the St. Lucie Unit 2 surveillance data in Appendix B of Reference 4.8.1 determined that the St. Lucie Unit 2 surveillance data for the Intermediate Shell Plate M-605-1 and Heat # 83637 are deemed credible.

4.2.3 Upper-Shelf Energy

TLAA Description

Upper-shelf energy (USE) is the parameter used to indicate the toughness of a material at elevated temperature. There are two sets of rules that govern USE acceptance criteria. 10 CFR 50, Appendix G, Paragraph IV.A.1.a, states that RPV 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 ASME Code, Section XI.

The current licensing basis upper-shelf energy (USE) calculations were prepared for PSL Units 1 and 2 RPV beltline and extended beltline materials for the 60-year PEO. Since the USE value is a function of neutron fluence which is associated with a specified operating period, the PSL Units 1 and 2 USE calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for the 80-year SPEO. The projected 80-year EFPY for both PSL Units 1 and 2 is assumed to be 72 EFPY.

TLAA Evaluation

There are two methods that can be used to predict the decrease in USE with irradiation, depending on the availability of credible surveillance capsule data as defined in Regulatory Guide (RG) 1.99. For RPV beltline and extended beltline materials that are not in the surveillance program or have non-credible data, the Charpy USE (Position 1.2) is assumed to decrease as a function of fluence and copper content, as indicated in RG 1.99. When two or more credible surveillance sets become available from the RPV, they may be used to determine the Charpy USE of the surveillance material. The surveillance data are then used in conjunction with RG 1.99 to predict the change in USE (Position 2.2) of the RPV material due to irradiation. Per RG 1.99, when credible data exist, the Position 2.2 projected USE value should be used in preference to the Position 1.2 projected USE value.

The 72 EFPY Position 1.2 USE values of the RPV materials can be predicted using the corresponding 1/4T fluence projections, the copper content of the materials, and Figure 2 in RG 1.99. Only those projected fluence values with a 1.1 bias on the peripheral and re-entrant corner assembly relative powers are considered.

The predicted Position 2.2 USE values are determined for the RPV materials that are contained in the surveillance program by using the reduced plant surveillance data along with the corresponding 1/4T fluence projection. The surveillance data for PSL Units 1 and 2 was plotted on RG 1.99, Revision 2, Figure 2 (see Figures 7-1 and 7-2 of Westinghouse Report WCAP-18609-NP). This data was fitted by drawing a line parallel to the existing lines as the upper bound of all the surveillance data. These reduced lines were used instead of the existing lines to determine the Position 2.2 USE values. Note, Position 2.2 USE projections are performed only for those PSL Units 1 and 2 RPV base metal materials from which the surveillance materials were extracted and weld metal materials with the same heat and flux type as the surveillance weld.

The projected USE values were calculated to determine if the PSL Units 1 and 2 beltline and extended beltline materials remain above the 50 ft-lb criterion at 72 EFPY. The USE calculations are summarized in Tables 4.2.3-1 and 4.2.3-2 for PSL Units 1 and 2, respectively. As shown in Tables 4.2.3-1 and 4.2.3-2, all of the PSL Units 1 and 2 RPV beltline and extended beltline materials are projected to remain above the USE screening criterion of 50 ft-lb (per 10 CFR 50, Appendix G) at 72 EFPY. The limiting PSL Unit 1 projected USE value for SPEO is intermediate shell plate C-7-3 with a projected USE of 54.8 ft-lb. The limiting PSL Unit 2 projected USE value for SPEO is lower shell plate M-4116-1 with a projected USE of 66.4 ft-lb.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The USE analyses have been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

Table 4.2.3-1: Predicted USE Values for the St. Lucie Unit 1 Beltline and Extended Beltline Materials at 72 EFPY

Material	Weight% Cu[(a)]	1/4T Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Unirradiated USE[(a)] (ft-lb)	Projected USE Decrease[(c)] (%)	Projected USE (ft-lb)
Beltline Materials Position 1.2 Results					
Intermediate Shell Plate C-7-1	0.11	3.80	81.9	28	59.0
Intermediate Shell Plate C-7-2	0.11	3.80	81.9	28	59.0
Intermediate Shell Plate C-7-3	0.11	3.80	76.05	28	54.8
Lower Shell Plate C-8-1	0.15	3.78	81.9	33	54.9
Lower Shell Plate C-8-2	0.15	3.78	103	33	69.0
Lower Shell Plate C-8-3	0.12	3.78	88.4	29	62.8
Intermediate to Lower Shell Girth Weld Seam 9-203 (Heat # 90136)	0.27	3.77	144	52	69.1
Intermediate Shell Axial Weld Seams 2-203 A, B, & C (Heat #'s 34B009 / A-8746)	0.19	2.33	102.3	41	60.4
Lower Shell Axial Weld Seams 3-203 A, B, & C (Heat # 305424)	0.27	2.31	112	49	57.1
Extended Beltline Materials Position 1.2 Results					
Upper Shell Plate C-6-1	0.16	0.179	68	17	56.4
Upper Shell Plate C-6-2	0.16	0.179	80	17	66.4
Upper Shell Plate C-6-3	0.16	0.179	84	17	69.7
Upper to Intermediate Shell Girth Weld Seam 8-203 (Heat # 21935)	0.183	0.225	109	24	82.8
Upper Shell Axial Seams 1-203 A, B, and C (Heat #'s 21935 / 12008)	0.213	0.225	118	26	87.3
Beltline Materials Position 2.2 Results					
Lower Shell Plate C-8-2	0.15	3.78	103	39	62.8
Intermediate to Lower Shell Girth Weld Seam 9-203 (Heat # 90136)	0.27	3.77	144	49	73.4

Notes:

(a) Copper weight percent values and unirradiated USE values were taken from Table 3-1 of Reference 4.8.1.

(b) Values taken from Table 8-3 of Reference 4.8.1. Only those projected fluence values with a 1.1 bias on the peripheral and re-entrant corner assembly relative powers are considered.

(c) Position 1.2 percentage USE decrease values were calculated by plotting the 1/4T fluence values on RG 1.99, Figure 2 and using the material-specific Cu wt. % values. Position 2.2 percentage USE decrease values were determined by drawing an upper-bound line parallel to the existing RG 1.99, Figure 2 lines through the applicable surveillance data points. These results should be used in preference to the existing graph lines for determining the decrease in USE, because the surveillance data is credible. The St. Lucie Unit 1 surveillance data use for the RG 1.99, Position 2.2 projection can be found in Table 4-1 of Reference 4.8.1.

Table 4.2.3-2: Predicted USE Values for the St. Lucie Unit 2 Beltline and Extended Beltline Materials at 72 EFPY

Material	Weight% Cu[(a)]	1/4T Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Unirradiated USE[(a)] (ft-lb)	Projected USE Decrease[(c)] (%)	Projected USE (ft-lb)
Beltline Materials Position 1.2 Results					
Intermediate Shell Plate M-605-1	0.11	3.91	105	29	74.6
Intermediate Shell Plate M-605-2	0.13	3.91	113	31	78.0
Intermediate Shell Plate M-605-3	0.11	3.91	113	29	80.2
Lower Shell Plate M-4116-1	0.06	3.89	91	27	66.4
Lower Shell Plate M-4116-2	0.07	3.89	105	27	76.7
Lower Shell Plate M-4116-3	0.07	3.89	100	27	73.0
Intermediate to Lower Shell Girth Weld Seam 101-171 (Heat #'s 83637 / 3P7317)	0.07	3.89	96	30	67.2
Intermediate Shell Axial Weld Seams 101-124A, B, & C (Heat # 83642)	0.05	2.57	116	24	88.2
Intermediate Shell Axial Weld Seam 101-124C Repair (Heat # 83637)	0.05	2.57	136	24	103.4
Lower Shell Axial Welds Seams 101-142A, B, & C (Heat # 83637)	0.05	2.56	136	24	103.4
Extended Beltline Materials Position 1.2 Results					
Upper Shell Plate M-604-1	0.16	0.0906	90	15	76.5
Upper Shell Plate M-604-2	0.16	0.0906	82	15	69.7
Upper Shell Plate M-604-3	0.16	0.0906	106	15	90.1
Upper to Intermediate Shell Girth Weld Seam 106-121 (Heat # 83637)	0.05	0.104	136	12	119.7
Upper Shell Axial Weld Seams 101-122A & C (Heat # 5P5622)	0.153	0.104	102	18	83.6
Upper Shell Axial Weld Seams 101-122A & C (Heat # 2P5755)	0.21	0.104	109	22	85.0
Upper Shell Axial Weld Seam 101-122B (Heat # 5P5622)	0.153	0.104	102	18	83.6
Hot Leg Nozzle A M-4103-2	0.127	0.0103[(d)]	107	9	97.4
Hot Leg Nozzle B M-4103-1	0.127	0.0103[(d)]	111	9	101.0
Hot Leg Nozzle to Shell Weld Seam 105-121A (Heat # 4P6519)	0.131	0.0103[(d)]	107	11	95.2
Hot Leg Nozzle to Shell Weld Seam 105-121B (Various SMAWs)	0.05	0.0103[(d)]	128	8	117.8
Beltline Materials Position 2.2 Results					
Intermediate Shell Plate M-605-1	0.11	3.91	105	32	71.4

Notes:

(a) Copper (Cu) weight percent values and unirradiated USE values were taken from Table 3-2 of Reference 4.8.1. If the base metal or weld Cu weight percentages are below the minimum value presented in Figure 2 of RG 1.99, Revision 2 (0.1 for base metal and 0.05 for welds), then the Cu weight percentages were conservatively rounded up to the minimum value for projected USE decrease determination.

(b) Values taken from Table 8-4 of Reference 4.8.1 . Fluence values above 10^{17} n/cm^2 (E > 1.0 MeV) but below 2 x 10^{17} n/cm^2 (E > 1.0 MeV) were rounded to 2 x 10^{17} n/cm^2 (E > 1.0 MeV) when determining the % decrease because 2 x 10^{17} n/cm^2 is the lowest fluence displayed in Figure 2 of RG 1.99. Only those projected fluence values with a 1.1 bias on the peripheral and re-entrant corner assembly relative powers are considered.

(c) Position 1.2 percentage USE decrease values were calculated by plotting the 1/4T fluence values on RG 1.99, Figure 2 and using the material-specific Cu wt. % values. The percent-loss lines were extended into the low fluence area of RG 1.99, Figure 2, (i.e., below 10^{18} n/cm^2), in order to determine the USE percent decrease, as needed. Position 2.2 percentage USE decrease values were determined by drawing an upper-bound line parallel to the existing RG 1.99, Figure 2 lines through the applicable surveillance data points. These results should be used in preference to the existing graph lines for determining the decrease in USE, because the surveillance data is credible. The St. Lucie Unit 2 surveillance data used for the RG 1.99; Position 2.2 projection can be found in Table 4-2 of Reference 4.8.1.

(d) Values are the maximum fluence values instead of the 1/4T fluence values.

4.2.4 Adjusted Reference Temperature

TLAA Description

The adjusted reference temperature (ART) of the limiting beltline or extended beltline material is used to adjust the beltline pressure-temperature (P-T) limit curves to account for irradiation effects. Regulatory Guide (RG)1.99, 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 ART is defined as: Initial RT_{NDT} + (ΔRT_{NDT}) + Margin. Since the ΔRT_{NDT} values are a function of neutron fluence, these ART calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for the 80-year SPEO.

TLAA Evaluation

The ART evaluation for the PSL Units 1 and 2 SPEO is presented in Section 8.1 of Westinghouse Report WCAP-18609-NP. Tables 4.2.4-1 and 4.2.4-2, below, provide the surface, 1/4T, and 3/4T fluence and fluence factor (FF) values for PSL Units 1 and 2 at 72 EFPY, respectively. The PSL Unit 1 ART calculation results for 72 EFPY are summarized in Table 4.2.4-3 for 1/4T and Table 4.2.4-4 for 3/4T. The PSL Unit 2 ART calculation results for 72 EFPY are summarized in Table 4.2.4-5 for 1/4T and Table 4.2.4-6 for 3/4T.

With regard to the reactor vessel nozzles for PSL Unit 1, the 72 EFPY projected fluences do not exceed 1×10^{17} n/cm^2, and therefore, the nozzles do not require evaluation for ART. For PSL Unit 2, Table 4.2.4-7 provides the 72 EFPY ART values for the hot leg nozzles because the 72 EYPY projected fluence does exceed 1×10^{17} n/cm^2.

The ART values of the limiting beltline and extended beltline materials at 72 EFPY for each unit are listed below:

- The limiting 72 EFPY ART values for PSL Unit 1 correspond to the lower shell axial weld, seams 3-203 A, B, & C (Heat # 305424).
- The limiting 72 EFPY ART values for PSL Unit 2 correspond to the intermediate shell plate M-605-1.

Section 8.2 of Westinghouse Report WCAP-18609-NP determines the applicability of the current end-of-license extension (EOLE) P-T limit curves by comparing the ART values contained in the PSL Units 1 and 2 P-T limits analyses of record with the ART values presented in Tables 4.2.4-3 through 4.2.4-7. If the ART values used in the current EOLE analysis are higher or equal to the ART values calculated using the updated 72 EFPY fluence, then the applicability term of the current curves will remain unchanged or possibly can be extended. If the ART values used in the previous analysis are lower than the ART values calculated using the updated fluence, then the applicability term of the current curves may need to be shortened. Results of the comparison conclude that the current PSL Units 1 and 2 P-T limit curves and low temperature overpressure protection (LTOP) enable temperatures remain valid through the EOLE.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The ART analyses have been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

Table 4.2.4-1 St. Lucie Unit 1 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)]
Beltline					
Intermediate Shell Plate C-7-1	6.38	3.80	1.345	1.35	1.084
Intermediate Shell Plate C-7-2	6.38	3.80	1.345	1.35	1.084
Intermediate Shell Plate C-7-3	6.38	3.80	1.345	1.35	1.084
Lower Shell Plate C-8-1	6.35	3.78	1.344	1.34	1.082
Lower Shell Plate C-8-2	6.35	3.78	1.344	1.34	1.082
Lower Shell Plate C-8-3	6.35	3.78	1.344	1.34	1.082
Intermediate to Lower Shell Girth Weld Seam 9-203	6.32	3.77	1.343	1.34	1.081
Intermediate Shell Axial Weld Seams 2-203 A, B, & C	3.91	2.33	1.229	0.828	0.947
Lower Shell Axial Weld Seams 3-203 A, B, & C	3.88	2.31	1.227	0.821	0.945
Extended Beltline					
Upper Shell Plate C-6-1	0.301	0.179	0.544	0.0637	0.333
Upper Shell Plate C-6-2	0.301	0.179	0.544	0.0637	0.333
Upper Shell Plate C-6-3	0.301	0.179	0.544	0.0637	0.333
Upper to Intermediate Shell Girth Weld Seam 8-203	0.377	0.225	0.598	0.0798	0.373
Upper Shell Axial Weld Seams 1-203 A, B, & C	0.377	0.225	0.598	0.0798	0.373

Notes:

(a) The 72 EFPY surface fluence values for the reactor vessel materials were taken from Table 2.4-5 of Reference 4.8.1. Only those projected fluence values with a 1.1 bias on the peripheral and re-entrant corner assembly relative powers are considered.

(b) The 1/4T and 3/4T fluence values were calculated from the surface fluence, the reactor vessel beltline thickness (8.625 inches) and equation $f = f_{surf} * e^{-0.24 (x)}$ from RG 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 St. Lucie Unit 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]
Beltline					
Intermediate Shell Plate M-605-1	6.56	3.91	1.351	1.39	1.091
Intermediate Shell Plate M-605-2	6.56	3.91	1.351	1.39	1.091
Intermediate Shell Plate M-605-3	6.56	3.91	1.351	1.39	1.091
Lower Shell Plate M-4116-1	6.53	3.89	1.350	1.38	1.090
Lower Shell Plate M-4116-2	6.53	3.89	1.350	1.38	1.090
Lower Shell Plate M-4116-3	6.53	3.89	1.350	1.38	1.090
Intermediate to Lower Shell Girth Weld Seam 101-171	6.52	3.89	1.350	1.38	1.090
Intermediate Shell Axial Weld Seams 101-124A, B, & C	4.31	2.57	1.253	0.913	0.974
Lower Shell Axial Welds Seams 101-142A, B, & C	4.29	2.56	1.252	0.908	0.973
Extended Beltline					
Upper Shell Plate M-604-1	0.152	0.0906	0.397	0.0322	0.229
Upper Shell Plate M-604-2	0.152	0.0906	0.397	0.0322	0.229
Upper Shell Plate M-604-3	0.152	0.0906	0.397	0.0322	0.229
Upper to Intermediate Shell Girth Weld Seam 106-121	0.175	0.104	0.425	0.0371	0.248
Upper Shell Axial Weld Seams 101-122A, B, & C	0.175	0.104	0.425	0.0371	0.248
Hot Leg Nozzle A M-4103-2	0.0103	Note (d)	0.112[d]	Note (d)	
Hot Leg Nozzle B M-4103-1	0.0103		0.112[d]		
Hot Leg Nozzle to Shell Weld Seam 105-121A	0.0103		0.112[d]		
Hot Leg Nozzle to Shell Weld Seam 105-121B	0.0103		0.112[d]		

Notes:

(a) The 72 EFPY surface fluence values for the reactor vessel materials were taken from Table 2.5-5 of Reference 4.8.1. Only those projected fluence values with a 1.1 bias on the peripheral and re-entrant corner assembly relative powers are considered.

(b) The 1/4T and 3/4T fluence values were calculated from the surface fluence, the reactor vessel beltline thickness (8.625 inches) and equation $f = f_{surf} * e^{-0.24\,(x)}$ from RG 1.99, Revision 2, where x = the depth into the vessel wall (inches).

(c) FF = fluence factor = $f^{\,(0.28 - 0.10*\log(f))}$.

(d) For conservatism, only the maximum fluence for the lowest extent of the hot leg nozzle to upper shell plate weld is considered. The FF shown in this table corresponds to the maximum fluence.

Table 4.2.4-3 Calculation of the St. Lucie Unit 1 ART Values at the 1/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at 72 EFPY

Material	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)
Beltline										
Intermediate Shell Plate C-7-1	1.1	74.60	3.80	1.345	0	100.3	0	17.0	34.0	134.3
Intermediate Shell Plate C-7-2	1.1	74.60	3.80	1.345	-10	100.3	0	17.0	34.0	124.3
Intermediate Shell Plate C-7-3	1.1	73.80	3.80	1.345	10	99.3	0	17.0	34.0	143.3
Lower Shell Plate C-8-1	1.1	107.80	3.78	1.344	20	144.9	0	17.0	34.0	198.9
with credible surveillance data[(e)]	2.1	81.84	3.78	1.344	20	110.0	0	8.5	17.0	147.0
Lower Shell Plate C-8-2	1.1	108.35	3.78	1.344	20	145.6	0	17.0	34.0	199.6
with credible surveillance data[(e)]	2.1	82.67	3.78	1.344	20	111.1	0	8.5	17.0	148.1
Lower Shell Plate C-8-3	1.1	82.60	3.78	1.344	0	111.0	0	17.0	34.0	145.0
with credible surveillance data[(e)]	2.1	62.83	3.78	1.344	0	84.5	0	8.5	17.0	101.5
Intermediate to Lower Shell Girth Weld Seam 9-203 (Heat # 90136)	1.1	124.25	3.77	1.343	-60	166.9	0	28.0	56.0	162.9
with credible surveillance data[(e)]	2.1	85.79	3.77	1.343	-60	115.2	0	14.0	28.0	83.2
Intermediate Shell Axial Weld Seams 2-203 A, B, & C (Heat #'s 34B009 / A-8746)	1.1	90.65	2.33	1.229	-56	111.4	17	28.0	65.5	120.9
Lower Shell Axial Weld Seams 3-203 A, B, & C (Heat # 305424)	1.1	188.80	2.31	1.227	-60	231.6	0	28.0	56.0	227.6
with non-credible Beaver Valley Unit 1 surveillance data[(e)]	2.1	176.28	2.31	1.227	-60	216.2	0	28.0	56.0	212.2

Table 4.2.4-3 Calculation of the St. Lucie Unit 1 ART Values at the 1/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at 72 EFPY (Continued)

Material	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)
Extended Beltline										
Upper Shell Plate C-6-1	1.1	113.10	0.179	0.544	33	61.5	0	17.0	34.0	128.5
Upper Shell Plate C-6-2	1.1	113.10	0.179	0.544	15	61.5	0	17.0	34.0	110.5
Upper Shell Plate C-6-3	1.1	113.10	0.179	0.544	15	61.5	0	17.0	34.0	110.5
Upper to Intermediate Shell Girth Weld Seam 8-203 (Heat # 21935)	1.1	172.22	0.225	0.598	-56	102.9	17	28.0	65.5	112.4
Upper Shell Axial Seams 1-203 A, B, and C (Heat #'s 21935 / 12008)	1.1	208.62	0.225	0.598	-50	124.7	0	28.0	56.0	130.7

Notes:

(a) Chemistry factors are taken from Table 5-4 of Reference 4.8.1.

(b) Fluence and fluence factors taken from Table 8-3 of Reference 4.8.1.

(c) $RT_{NDT(U)}$ values taken from Table 3-1 of Reference 4.8.1.

(d) Per the guidance of RG 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per RG 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed 0.5*ΔRT_{NDT} for either base metals or welds, with or without surveillance data.

(e) The credibility evaluation for the St. Lucie Unit 1 surveillance data in Appendix B of Reference 4.8.1 determined that the St. Lucie Unit 1 surveillance data for the Lower Shell Plate C-8-2 and Heat # 90136 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. The Beaver Valley Unit 1 Heat # 305424 surveillance weld was determined to be non-credible in WCAP-18102-NP.

Table 4.2.4-4 Calculation of the St. Lucie Unit 1 ART Values at the 3/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at 72 EFPY

Material	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)
Beltline										
Intermediate Shell Plate C-7-1	1.1	74.60	1.35	1.084	0	80.8	0	17.0	34.0	114.8
Intermediate Shell Plate C-7-2	1.1	74.60	1.35	1.084	-10	80.8	0	17.0	34.0	104.8
Intermediate Shell Plate C-7-3	1.1	73.80	1.35	1.084	10	80.0	0	17.0	34.0	124.0
Lower Shell Plate C-8-1	1.1	107.80	1.34	1.082	20	116.7	0	17.0	34.0	170.7
with credible surveillance data[e]	2.1	81.84	1.34	1.082	20	88.6	0	8.5	17.0	125.6
Lower Shell Plate C-8-2	1.1	108.35	1.34	1.082	20	117.3	0	17.0	34.0	171.3
with credible surveillance data[e]	2.1	82.67	1.34	1.082	20	89.5	0	8.5	17.0	126.5
Lower Shell Plate C-8-3	1.1	82.60	1.34	1.082	0	89.4	0	17	34.0	123.4
with credible surveillance data[e]	2.1	62.83	1.34	1.082	0	68.0	0	8.5	17.0	85.0
Intermediate to Lower Shell Girth Weld Seam 9-203 (Heat # 90136)	1.1	124.25	1.34	1.081	-60	134.3	0	28.0	56.0	130.3
with credible surveillance data[e]	2.1	85.79	1.34	1.081	-60	92.7	0	14.0	28.0	60.7
Intermediate Shell Axial Weld Seams 2-203 A, B, & C (Heat #'s 34B009 / A-8746)	1.1	90.65	0.828	0.947	-56	85.8	17	28.0	65.5	95.4
Lower Shell Axial Weld Seams 3-203 A, B, & C (Heat # 305424)	1.1	188.80	0.821	0.945	-60	178.4	0	28.0	56.0	174.4
with non-credible Beaver Valley Unit 1 surveillance data[e]	2.1	176.28	0.821	0.945	-60	166.6	0	28.0	56.0	162.6

Table 4.2.4-4 Calculation of the St. Lucie Unit 1 ART Values at the 3/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at 72 EFPY (Continued)

Material	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)
Extended Beltline										
Upper Shell Plate C-6-1	1.1	113.10	0.0637	0.333	33	37.6	0	17.0	34.0	104.6
Upper Shell Plate C-6-2	1.1	113.10	0.0637	0.333	15	37.6	0	17.0	34.0	86.6
Upper Shell Plate C-6-3	1.1	113.10	0.0637	0.333	15	37.6	0	17.0	34.0	86.6
Upper to Intermediate Shell Girth Weld Seam 8-203 (Heat # 21935)	1.1	172.22	0.0798	0.373	-56	64.3	17	28.0	65.5	73.8
Upper Shell Axial Seams 1-203 A, B, and C (Heat #'s 21935 / 12008)	1.1	208.62	0.0798	0.373	-50	77.9	0	28.0	56.0	83.9

Notes:

(a) Chemistry factors are taken from Table 5-4 of Reference 4.8.1.

(b) Fluence and fluence factors taken from Table 8-3 of Reference 4.8.1.

(c) $RT_{NDT(U)}$ values taken from Table 3-1 of Reference 4.8.1.

(d) Per the guidance of RG 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per RG 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed $0.5*\Delta RT_{NDT}$ for either base metals or welds, with or without surveillance data.

(e) The credibility evaluation for the St. Lucie Unit 1 surveillance data in Appendix B of Reference 4.8.1 determined that the St. Lucie Unit 1 surveillance data for the Lower Shell Plate C-8-2 and Heat # 90136 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. The Beaver Valley Unit 1 Heat # 305424 surveillance weld was determined to be non-credible in WCAP-18102-NP.

Table 4.2.4-5 Calculation of the St. Lucie Unit 2 ART Values at the 1/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at 72 EFPY

Material	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)
Beltline										
Intermediate Shell Plate M-605-1	1.1	74.15	3.91	1.351	30	100.2	0	17.0	34.0	164.2
with credible surveillance data[(e)]	2.1	102.12	3.91	1.351	30	138.0	0	8.5	17.0	185.0
Intermediate Shell Plate M-605-2	1.1	91.50	3.91	1.351	10	123.6	0	17.0	34.0	167.6
Intermediate Shell Plate M-605-3	1.1	74.15	3.91	1.351	0	100.2	0	17.0	34.0	134.2
with credible surveillance data[(e)]	2.1	102.12	3.91	1.351	0	138.0	0	8.5	17.0	155.0
Lower Shell Plate M-4116-1	1.1	37.00	3.89	1.350	20	50.0	0	17.0	34.0	104.0
Lower Shell Plate M-4116-2	1.1	44.00	3.89	1.350	20	59.4	0	17.0	34.0	113.4
Lower Shell Plate M-4116-3	1.1	44.00	3.89	1.350	20	59.4	0	17.0	34.0	113.4
Intermediate to Lower Shell Girth Weld Seam 101-171 (Heat #'s 83637 / 3P7317)	1.1	40.05	3.89	1.350	-50	54.1	0	27.0	54.1	58.1
Intermediate Shell Axial Weld Seams 101-124A, B, & C (Heat # 83642)	1.1	36.35	2.57	1.253	-56	45.5	17	22.8	56.8	46.4
Intermediate Shell Axial Weld Seam 101-124C Repair (Heat # 83637)	1.1	34.05	2.57	1.253	-50	42.7	0	21.3	42.7	35.3
with credible surveillance data[(e)]	2.1	23.55	2.57	1.253	-50	29.5	0	14.0	28.0	7.5
Lower Shell Axial Welds Seams 101-142A, B, & C (Heat # 83637)	1.1	34.05	2.56	1.252	-50	42.6	0	21.3	42.6	35.2
with credible surveillance data[(e)]	2.1	23.55	2.56	1.252	-50	29.5	0	14.0	28.0	7.5

Table 4.2.4-5 Calculation of the St. Lucie Unit 2 ART Values at the 1/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at 72 EFPY (Continued)

Material	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)
Extended Beltline										
Upper Shell Plate M-604-1	1.1	118.00	0.0906	0.397	50	46.9	0	17.0	34.0	130.9
Upper Shell Plate M-604-2	1.1	118.25	0.0906	0.397	50	47.0	0	17.0	34.0	131.0
Upper Shell Plate M-604-3	1.1	116.60	0.0906	0.397	10	46.3	0	17.0	34.0	90.3
Upper to Intermediate Shell Girth Weld Seam 106-121 (Heat # 83637)	1.1	34.05	0.104	0.425	-50	14.5	0	7.2	14.5	-21.0
with credible surveillance data[(e)]	2.1	23.55	0.104	0.425	-50	10.0	0	5.0	10.0	-30.0
Upper Shell Axial Weld Seams 101-122A & C (Heat # 5P5622)	1.1	74.13	0.104	0.425	-40	31.5	0	15.8	31.5	23.1
Upper Shell Axial Weld Seams 101-122A & C (Heat # 2P5755)	1.1	96.64	0.104	0.425	-50	41.1	0	20.6	41.1	32.2
Upper Shell Axial Weld Seam 101-122B (Heat # 5P5622)	1.1	74.13	0.104	0.425	-40	31.5	0	15.8	31.5	23.1

Notes:

(a) Chemistry factors are taken from Table 5-5 of Reference 4.8.1.

(b) Fluence and fluence factors taken from Table 8-4 of Reference 4.8.1.

(c) $RT_{NDT(U)}$ values taken from Table 3-2 of Reference 4.8.1.

(d) Per the guidance of RG 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per RG 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed 0.5*ΔRT_{NDT} for either base metals or welds, with or without surveillance data.

(e) The credibility evaluation for the St. Lucie Unit 2 surveillance data in Appendix B of Reference 4.8.1 determined that the St. Lucie Unit 2 surveillance data for the Intermediate Shell Plate M-605-1 and Heat # 83637 are deemed credible.

Table 4.2.4-6 Calculation of the St. Lucie Unit 2 ART Values at the 3/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at 72 EFPY

Material	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)
Beltline										
Intermediate Shell Plate M-605-1	1.1	74.15	1.39	1.091	30	80.9	0	17.0	34.0	144.9
with credible surveillance data[(e)]	2.1	102.12	1.39	1.091	30	111.4	0	8.5	17.0	158.4
Intermediate Shell Plate M-605-2	1.1	91.50	1.39	1.091	10	99.8	0	17.0	34.0	143.8
Intermediate Shell Plate M-605-3	1.1	74.15	1.39	1.091	0	80.9	0	17.0	34.0	114.9
with credible surveillance data[(e)]	2.1	102.12	1.39	1.091	0	111.4	0	8.5	17.0	128.4
Lower Shell Plate M-4116-1	1.1	37.00	1.38	1.090	20	40.3	0	17.0	34.0	94.3
Lower Shell Plate M-4116-2	1.1	44.00	1.38	1.090	20	48.0	0	17.0	34.0	102.0
Lower Shell Plate M-4116-3	1.1	44.00	1.38	1.090	20	48.0	0	17.0	34.0	102.0
Intermediate to Lower Shell Girth Weld Seam 101-171 (Heat #'s 83637 / 3P7317)	1.1	40.05	1.38	1.090	-50	43.6	0	21.8	43.6	37.3
Intermediate Shell Axial Weld Seams 101-124A, B, & C (Heat # 83642)	1.1	36.35	0.913	0.974	-56	35.4	17	17.7	49.1	28.5
Intermediate Shell Axial Weld Seam 101-124C Repair (Heat # 83637)	1.1	34.05	0.913	0.974	-50	33.2	0	16.6	33.2	16.4
with credible surveillance data[(e)]	2.1	23.55	0.913	0.974	-50	22.9	0	11.5	22.9	-4.1
Lower Shell Axial Welds Seams 101-142A, B, & C (Heat # 83637)	1.1	34.05	0.908	0.973	-50	33.1	0	16.6	33.1	16.3
with credible surveillance data[(e)]	2.1	23.55	0.908	0.973	-50	22.9	0	11.5	22.9	-4.2

Table 4.2.4-6 Calculation of the St. Lucie Unit 2 ART Values at the 3/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at 72 EFPY (Continued)

Material	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)
Extended Beltline										
Upper Shell Plate M-604-1	1.1	118.00	0.0322	0.229	50	27.0	0	13.5	27.0	104.0
Upper Shell Plate M-604-2	1.1	118.25	0.0322	0.229	50	27.1	0	13.5	27.1	104.1
Upper Shell Plate M-604-3	1.1	116.60	0.0322	0.229	10	26.7	0	13.3	26.7	63.3
Upper to Intermediate Shell Girth Weld Seam 106-121 (Heat # 83637)	1.1	34.05	0.0371	0.248	-50	8.4	0	4.2	8.4	-33.1
with credible surveillance data[e]	2.1	23.55	0.0371	0.248	-50	5.8	0	2.9	5.8	-38.3
Upper Shell Axial Weld Seams 101-122A & C (Heat # 5P5622)	1.1	74.13	0.0371	0.248	-40	18.4	0	9.2	18.4	-3.2
Upper Shell Axial Weld Seams 101-122A & C (Heat # 2P5755)	1.1	96.64	0.0371	0.248	-50	24.0	0	12.0	24.0	-2.1
Upper Shell Axial Weld Seam 101-122B (Heat # 5P5622)	1.1	74.13	0.0371	0.248	-40	18.4	0	9.2	18.4	-3.2

Notes:

(a) Chemistry factors are taken from Table 5-5 of Reference 4.8.1.

(b) Fluence and fluence factors taken from Table 8-4 of Reference 4.8.1.

(c) $RT_{NDT(U)}$ values taken from Table 3-2 of Reference 4.8.1.

(d) Per the guidance of RG 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per RG 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed 0.5*ΔRT_{NDT} for either base metals or welds, with or without surveillance data.

(e) The credibility evaluation for the St. Lucie Unit 2 surveillance data in Appendix B of Reference 4.8.1 determined that the St. Lucie Unit 2 surveillance data for the Intermediate Shell Plate M-605-1 and Heat # 83637 are deemed credible.

Table 4.2.4-7 Calculation of the St. Lucie Unit 2 ART Values for the Hot Leg Nozzle Materials at 72 EFPY

Material	R.G. 1.99, Rev. 2 Position	CF[(a)]	Maximum Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	FF[(b)]	$RT_{NDT(U)}$[(c)] (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ[(d)] (°F)	M (°F)	ART (°F)
Hot Leg Nozzle A M-4103-2	1.1	89.92	0.0103	0.112	-30	10.1	0	5.0	10.1	-9.9
Hot Leg Nozzle B M-4103-1	1.1	90.36	0.0103	0.112	-20	10.1	0	5.1	10.1	0.2
Hot Leg Nozzle to Shell Weld Seam 105-121A (Heat # 4P6519)	1.1	63.70	0.0103	0.112	-60	7.1	0	3.6	7.1	-45.7
Hot Leg Nozzle to Shell Weld Seam 105-121B (Various SMAWs)	1.1	68.00	0.0103	0.112	-60	7.6	0	3.8	7.6	-44.8

Notes:

(a) Chemistry factors are taken from Table 5-5 of Reference 4.8.1.

(b) Fluence and fluence factors taken from Table 8-4 of Reference 4.8.1.

(c) $RT_{NDT(U)}$ values taken from Table 3-2 of Reference 4.8.1.

(d) Per the guidance of RG 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per RG 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed 0.5*ΔRT_{NDT} for either base metals or welds, with or without surveillance data.

4.2.5 Pressure-Temperature Limits and 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 54 EFPY for PSL Unit 1 and 55 EFPY for PSL Unit 2. 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. In addition and as described in Section 4.1.4, there are two currently active 10 CFR 50.12 exemption requests, one for PSL Unit 1 and one for PSL Unit 2, that relate to the P-T limits time sensitive TLAA topic.

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 PSL P-T limits for the SPEO will be updated prior to expiration of the P-T limits for the current period of operation.

P-T limits for the Unit 1 RCS are contained in Section 3/4.4.9 of the Unit 1 Technical Specifications. The current Unit 1 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 54 EFPY. The Unit 1 Technical Specification Limiting Condition for Operation (LCO) 3.4.9.1 states that the RCS (except the pressurizer) temperature and pressure shall be limited in accordance with the limit lines shown in Figures 3.4-2a and 3.4-2b during heatup, cooldown, criticality, and in-service leak and hydrostatic testing. In addition, Technical Specification LCO 3.4.13 specifies the power operated relief valve (PORV) lift settings required to mitigate the consequences of LTOP events.

P-T limits for the Unit 2 RCS are contained in Section 3/4.4.9 of the Unit 2 Technical Specifications. The current Unit 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 55 EFPY. The Unit 2 Technical Specification LCO 3.4.9.1 states that the RCS (except the pressurizer) temperature and pressure shall be limited in accordance with the limit lines shown in Figures 3.4-2 and 3.4-3 during heatup, cooldown, criticality, and in-service testing. In addition, Technical Specification LCO 3.4.9.3 specifies the PORV and the shutdown cooling relief valve lift settings required to mitigate the consequences of LTOP events.

Prior to exceeding 54 EFPY on Unit 1 and 55 EFPY on Unit 2, new P-T limit curves will be generated to cover plant operation beyond those periods. 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. Each time the P-T limit curves are revised, the Unit 1 LTOP PORV lift setting and Unit 2 LTOP PORV and shutdown cooling relief valve lift settings must be reevaluated. Therefore, LTOP protection limits are considered part of the calculation of P-T curves.

The current 54 EFPY and 55 EFPY P-T limits for PSL Units 1 and 2 requested an exemption from the requirements of 10 CFR 50, Appendix G, to use the methodology of Topical Report CE NPSD-683-A, Rev 06, (Reference ML011350387) for the generation of the current P-T limits for the PSL Units 1 and 2 reactor coolant pressure boundary during normal operating and hydrostatic or leak rate testing conditions. In accordance with 10 CFR 50.12, the use of these exemptions was approved by the NRC in letters dated December 6, 2011 (Reference ML11297A096) and April 30, 2012 (Reference ML12096A270) for PSL Units 1 and 2, respectively. The TLAA evaluation above provides justification for continuation of these TLAA-related exemptions through 54 EFPY (PSL Unit 1) and 55 EFPY (Unit 2). Since these exemptions granted under 10 CFR 50.12 pertain to the derivation of P-T limits, that prior to the expiration of the current values/analyses which are approved for 54 EFPY (Unit 1) and 55 EFPY (Unit 2), the P-T limits values will be renewed in accordance with 10 CFR 50.90 and the subject exemptions, if needed, will be re-submitted as part of the 10 CFR 50.90 process. Therefore, the exemptions have been justified, to the extent practicable, through the end of the SPEO.

The P-T limit curves and LTOP PORV setpoints will be updated (if required) and a Technical Specification change request will be submitted, as required, prior to exceeding the current 54 EFPY limits for Unit 1 and 55 EFPY limits for Unit 2.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging on the intended function(s) of the Unit 1 and Unit 2 reactor vessels will be adequately managed for the SPEO. The Reactor Vessel Material Surveillance AMP (Section B.2.3.19) provides reasonable assurance that updated P-T limits and LTOP setpoints will be updated and submitted to the NRC prior to exceeding the current terms of applicability in the Technical Specifications for PSL Units 1 and 2, in accordance with 10 CFR 54.21(c)(1)(iii).

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 TLAA within the current licensing basis that would require evaluation for the subsequent period of extended operation. Searches were performed to identify these and any other potential fatigue TLAA within the current licensing bases for PSL Units 1 and 2. Each of the potential TLAA were evaluated against the six elements of the TLAA definition specified in 10 CFR 54.3. Those that were identified as fatigue TLAA are described and evaluated in the following subsections:

- “Metal Fatigue of Class 1 Components” (Section 4.3.1)
- “Metal Fatigue of Non-Class 1 Components” (Section 4.3.2)
- “Environmentally-Assisted Fatigue” (Section 4.3.3)
- “High-Energy Line Break Analyses” (Section 4.3.4)

4.3.1 <u>Metal Fatigue of Class 1 Components</u>

The PSL Units 1 and 2 reactor vessels, control element drive mechanisms, RCS piping (Unit 2 only), steam generators, reactor coolant pumps, pressurizers, and reactor vessel internals were originally designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Class 1. The PSL Unit 1 RCS piping was originally designed and fabricated in accordance with the ANSI B31.7, “Nuclear Power Piping” Class 1 requirements. The ASME Boiler and Pressure Vessel Code, Section III, Class 1 and ANI B31.7, “Nuclear Power Piping”, Class 1 Codes require a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded. Fatigue analyses were prepared for the PSL Units 1 and 2 Class 1 RCS pressure boundary components to determine the effects of cyclic loadings resulting from changes in system temperature and pressure. These ASME Section III, Class 1 and ANSI B31.7, Class 1, fatigue analyses were 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 (CUF) would 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 PSL Units 1 and 2 current licensing bases, are used to support safety determinations, and the number of occurrences of each transient type is currently 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. Sections 3.9 and 5.2.1.2 of the PSL Unit 1 UFSAR and Section 3.9 of the PSL Unit 2 UFSAR contain a listing of each of the transient conditions and associated design cycles. 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 for PSL Units 1 and 2 are based upon the original number of 40-year design cycles which were determined to bound the current 60-year period of extended operation.

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 PSL Units 1 and 2 UFSARs were reviewed.

For the PEO, PSL Units 1 and 2 have implemented a Fatigue Monitoring Program to ensure that the significant "fatigue-sensitive" design transient counts are not exceeded during plant operation. A comprehensive review of each RCS Class 1 component fatigue analysis was performed as part of first license renewal to determine which design transients were a significant contributor to overall fatigue usage.

For the SPEO, Westinghouse Report LTR-SDA-II-20-032-NP (Reference 4.8.5) provides a summary of the evaluation of PSL Units 1 and 2 80-year projected transient cycles. The evaluation includes a review of Fatigue Monitoring program data to identify the number of cumulative cycle counts for each transient type monitored on each unit up to December 31, 2019. Baseline cycle counts were projected to an 80-year operating life based on two methods. The first method calculated the projected 80-year cycles based on a direct extrapolation of the cycle counts through the SPEO. The second method calculated the projected 80-year cycles based on cycle accumulation over the last 10 years, and then pro-rated for the remaining years to the end of the SPEO. Additional details regarding cycle projections are included in Westinghouse Report LTR-SDA-II-20-032-NP.

The Westinghouse report projected 80-year cycles for the transients included in the original PSL Units 1 and 2 LRA and are presented in Tables 4.3.1-1 and 4.3.1-2, respectively. During the review of selected transient projections in these two tables for the SPEO, it was determined that the cycle limit for the PSL Units 1 and 2 loss of letdown flow needed to be increased to 500 cycles. Updates to the PSL Units 1 and 2 UFSARs to reflect the increase in loss of letdown flow cycle limits are included in Appendices A1 and A2, respectively.

The transients which are included in the current PSL Fatigue Monitoring program but not included in the original PSL LRA for PSL Units 1 and 2 are presented in Tables 4.3.1-3 and 4.3.1-4, respectively. Tables 4.3.1-5 and 4.3.1-6 include the Westinghouse report's 80-year projections for additional transients, including the loss of letdown flow cycle increase, that support SPEO fatigue evaluations.

As shown in Tables 4.3.1-1 through 4.3.1-6, with the exception of the loss of letdown flow transient, the Westinghouse report's projected cycles for 80 years of plant operation are less than the 40-year design cycles, or current licensing basis (CLB) cycles, used in the Class 1 component fatigue analyses. Tables 4.3.1-5 and 4.3.1-6 show that the Westinghouse report's 80-year projected cycles for the loss of letdown flow transient remains below the new limit of 500 cycles. The affected Class 1 RCS piping component fatigue analyses have been updated to incorporate the new cycle limit of 500 for the loss of letdown flow transient, as discussed below.

The severities of the Class 1 design transients were evaluated in Section 2.2.6 of the PSL Units 1 and 2 Extended Power Uprate (EPU) license amendment requests (LARs) (References ML12181A019 and ML110730116, respectively). The revised EPU design transients were determined to be conservative representations of actual plant transients and provided confidence that the component fatigue analyses were 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 severities remain conservative and valid for the proposed 80-year SPEO.

<u>Class 1 Component Fatigue Analysis</u>

The following sections provide a summary of the PSL Units 1 and 2 Class 1 component fatigue analyses acceptability for the 80-year SPEO.

<u>Reactor Vessels</u>

The PSL Unit 1 reactor vessel (RV) was designed and fabricated in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code Section III, Class A, 1965 Edition through Winter 1967 Addenda. The PSL Unit 1 reactor vessel closure head (RVCH) was replaced in 2005 with a head designed in accordance with ASME Section III, 1989 Edition, with no addenda.

A design review of the PSL Unit 1 RV and replacement RVCH was performed as part of the EPU project. Details of the review are included in Section 2.2.2.3 of the PSL Unit 1 EPU LAR. Tables 2.2.2.3-1, 2.2.2.3-2, and 2.2.2.3-3 of the EPU LAR provide significant results from the review, including a listing of cumulative usage factors (CUF) for selected RV and replacement RVCH component locations. All of the CUF values presented are below the acceptance criteria of 1.0. As shown in Tables 4.3.1-1, 4.3.1-3, and 4.3.1-5, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 1 RV and replacement RVCH will remain less than unity during the SPEO.

The PSL Unit 2 RV was designed and fabricated in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code Section III, Class 1, 1971 Edition through Summer 1972 Addenda. The PSL Unit 2 reactor vessel closure head (RVCH) was replaced in 2007 with a head designed in accordance with ASME Section III, 1989 Edition, with no addenda.

A design review of the PSL Unit 2 RV and replacement RVCH was performed as part of the EPU project. Details of the review are included in Section 2.2.2.3 of the PSL Unit 2 EPU LAR. Tables 2.2.2.3-1, 2.2.2.3-2, and 2.2.2.3-3 of the EPU LAR provide significant results from the review, including a listing of cumulative usage factors (CUF) for selected RV and replacement RVCH component locations. All of the CUF values presented are below the acceptance criteria of 1.0. As shown in Tables 4.3.1-2, 4.3.1-4, and 4.3.1-6, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 2 RV and replacement RVCH will remain less than unity during the SPEO.

Control Element Drive Mechanisms

The original PSL Units 1 and 2 control element drive mechanisms (CEDMs) were replaced as part of the modification that replaced both the PSL Units 1 and 2 RVCH. The PSL Units 1 and 2 replacement CEDMs were designed and fabricated in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code Section III, Division 1, 1998 Edition through 2000 Addenda. A design review of the PSL Units 1 and 2 CEDMs was performed as part of each units EPU project. Details of the review are included in Section 2.2.2.4 of the PSL Unit 1 EPU LAR and in Section 2.2.2.4 of the PSL Unit 2 EPU LAR. A summary of the maximum stresses and fatigue usage factors for each of the PSL Unit 1 CEDM pressure boundary components for EPU conditions is presented in PSL Unit 1 EPU LAR Tables 2.2.2.4-2 through 2.2.2.4-7 and a summary of the maximum stresses and fatigue usage factors for each of the PSL Unit 2 CEDM pressure boundary components for EPU conditions is presented in PSL Unit 2 EPU LAR Tables 2.2.2.4-2 through 2.2.2.4-6. Since all stress and fatigue limits are satisfied, the CEDMs are structurally qualified for EPU conditions. As shown in Tables 4.3.1-1, 4.3.1-3, and 4.3.1-5 for PSL Unit 1 and Tables 4.3.1-2, 4.3.1-4, and 4.3.1-6, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUF for the PSL Units 1 and 2 CEDMs will remain less than unity during the SPEO.

Reactor Coolant Piping

The PSL Unit 1 RCS piping was originally designed and fabricated in accordance with the ANSI B31.7, Class I, February 1, 1968 Draft Edition for Trial Use and Comment. The pressurizer surge line was subsequently analyzed to the acceptance criteria of ASME Code, Section III, 1986 in order to address the effects of thermal stratification on stress and fatigue in accordance with NRC Bulletin 88-11 (Reference ML031220290). In addition, structural weld overlays (SWOLs) were implemented on several PSL Unit 1 RCS piping and nozzle locations to eliminate concerns with stress corrosion cracking of Alloy 182 dissimilar metal welds. The SWOLs were analyzed in accordance with the requirements of ASME Section III, 1971 Edition through Summer 1972 Addendum.

A design review of the PSL Unit 1 RCS piping was performed as part of the EPU project. Details of the review are included in Section 2.2.2.1 of the PSL Unit 1 EPU LAR. Table 2.2.2.1-1 of the EPU LAR provides results from the review for all RCS piping, with the exception of the pressurizer surge line, and includes a listing of CUF values which remain within allowable limits. Table 2.2.2.1-2 provides the results and acceptable CUF values for the pressurizer surge line. As shown in Tables 4.3.1-1, 4.3.1-3, and 4.3.1-5, with the exception of the loss of letdown flow transient, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year

SPEO. The loss of letdown flow transient is considered in the fatigue analyses of record (AORs) for the PSL Unit 1 Class 1 cold leg charging nozzles, charging piping, and letdown piping. These analyses have been reconciled for the SPEO using 500 loss of letdown flow cycles. To accomplish this, the detailed fatigue results for the limiting component locations were extracted from the AORs and the component CUF was recalculated considering 500 loss of letdown flow cycles. The results demonstrate that the charging nozzles, charging piping, and letdown piping meet the CUF acceptance criterion assuming 500 loss of letdown flow cycles. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 1 RCS piping will remain less than unity during the SPEO.

The PSL Unit 2 RCS piping was designed and fabricated in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, 1971 Edition through Winter 1972 Addenda. The pressurizer surge line was subsequently analyzed to the acceptance criteria of ASME Code, Section III, 1986 in order to address the effects of thermal stratification on stress and fatigue in accordance with NRC Bulletin 88-11. In addition, SWOLs were implemented on several PSL Unit 2 RCS piping and nozzle locations to eliminate concerns with stress corrosion cracking of Alloy 182 dissimilar metal welds. The SWOLs were analyzed in for fatigue in accordance with the requirements of ASME Section III, 1998 Edition through 2000 Addendum.

A design review of the PSL Unit 2 RCS piping was performed as part of the EPU project. Details of the review are included in Section 2.2.2.1 of the PSL Unit 2 EPU LAR. The maximum RCS piping stresses and CUF for the EPU and the corresponding code allowables are presented in EPU LAR Table 2.2.2.1-1 for all RCS piping except the surge line, whose stresses and maximum CUF are summarized in LR Table 2.2.2.1-2. The results tabulated in Tables 2.2.2.1-1 and 2.2.2.1-2 show the RCS piping stresses and CUF are within the code allowable limits. As shown in Tables 4.3.1-2, 4.3.1-4, and 4.3.1-6, with the exception of the loss of letdown flow transient, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. The loss of letdown flow transient is considered in the fatigue analyses of record (AORs) for the PSL Unit 2 Class 1 cold leg charging nozzles, charging piping, and letdown piping. These analyses have been reconciled for the SPEO using 500 loss of letdown flow cycles. To accomplish this, the detailed fatigue results for the limiting component locations were extracted from the AORs and the component CUF was recalculated considering 500 loss of letdown flow cycles. The results demonstrate that the charging nozzles, charging piping, and letdown piping meet the CUF acceptance criterion assuming 500 loss of letdown flow cycles. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 2 RCS piping will remain less than unity during the SPEO.

Steam Generators

The original PSL Unit 1 steam generators (SGs) were replaced in 1997. The replacement SGs were designed and fabricated in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1986 Edition with no addenda. The review of the replacement steam generators was included as part of the original PSL Units 1 and 2 license renewal application.

A design review of the PSL Unit 1 replacement SGs was performed as part of the EPU project. Details of the review are included in Section 2.2.2.5 of the PSL Unit 1 EPU LAR. Tables 2.2.2.5-3 and 2.2.2.5-4 of the EPU LAR provide significant results from the review, including a listing of cumulative usage factors (CUF) for selected SG component locations. All of the CUF values presented are below the acceptance criteria of 1.0. As shown in Tables 4.3.1-1, 4.3.1-3, and 4.3.1-5, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 1 replacement SGs will remain less than unity during the SPEO.

The original PSL Unit 2 SGs were replaced in 2007. The replacement SGs were designed and fabricated in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components Class 1 and 2, 1998 Edition through 2000 Addenda. A design review of the PSL Unit 2 SGs was performed as part of the EPU project. Details of the review are included in Section 2.2.2.5 of the PSL Unit 2 EPU LAR. Table 2.2.2.5-9 of the EPU LAR provides significant results from the review, including a listing of cumulative usage factors (CUF) for selected replacement SG component locations. All of the CUF values presented are below the acceptance criteria of 1.0.

During startup from the PSL Unit 2 2014 refueling outage, foreign material in the RCS migrated to the 2B replacement SG hot leg. The loose part caused damage to the SG hot leg channel head internals. One hot leg plug was removed and replaced. An engineering evaluation was issued to address the loose part found inside the channel head and determine the acceptability of the as-left condition. A fatigue re-evaluation of the 2B replacement SG primary side hot leg components was performed by the supplier to assess the impact on the fatigue life of the components due to the damage. A one-time inspection of all 2B replacement SG primary-side components, including the tube-to-tubesheet welds, was performed during the next refueling outage. The follow-up visual inspection results confirmed that there was no breach in the cladding, no physical changes were observed in the material condition of the replacement SG hot leg channel head components compared to the visual inspection results from 2014 refueling outage, and the integrity of the RCS pressure boundary was maintained.

As noted in Tables 4.3.1-2 and 4.3.1-4, the fatigue re-evaluation of the 2B replacement SG hot leg channel head resulted in the reduction of five transient cycle limits. However, as shown in the tables, the 80-year projection for these 5 transients remain below the reduced cycle limits. As shown in Tables 4.3.1-2, 4.3.1-4, and 4.3.1-6, the 40-year design cycles (CLB cycles) and the reduced transient cycle limits for the 2B replacement SG bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 2 replacement SGs will remain less than unity during the SPEO.

Reactor Coolant Pumps

The PSL Unit 1 reactor coolant pumps (RCPs) were designed and fabricated in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code Section III, Nuclear Vessels, Class A, 1965 Edition through the Winter of 1967 Addenda. A design review of the PSL Unit 1 RCPs was performed as part of the EPU project. Details of the review are included in Section 2.2.2.6 of the PSL Unit 1 EPU LAR.

The review concluded the that, with one exception, the RCS temperatures, pressures, and design transients defined for the EPU either did not change from or were bounded by those transients considered in the pre-EPU analyses of record. The one exception was a 1°F temperature increase in the plant loading and unloading transient results for the EPU. This change was determined to have a negligible effect on RCS primary component stresses and fatigue, including the RCPs. As shown in Tables 4.3.1-1, 4.3.1-3, and 4.3.1-5, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 1 RCPs will remain less than unity during the SPEO.

The PSL Unit 2 RCPs were designed and fabricated in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, 1971 Edition through Summer 1973 Addenda. A design review of the PSL Unit 2 RCPs was performed as part of the EPU project. Details of the review are included in Section 2.2.2.6 of the PSL Unit 2 EPU LAR. Similar to the evaluation above for the PSL Unit 1 RCPs, the review concluded the that, with one exception, the RCS temperatures, pressures, and design transients defined for the EPU either did not change from or were bounded by those transients considered in the pre-EPU analyses of record. The one exception was a 1°F temperature increase in the plant loading and unloading transient results for the EPU. This change was determined to have a negligible effect on RCS primary component stresses and fatigue, including the PSL Unit 2 RCPs. As shown in Tables 4.3.1-2, 4.3.1-4, and 4.3.1-6, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 2 RCPs will remain less than unity during the SPEO.

Pressurizers

The PSL Unit 1 pressurizer was replaced in 2005. The replacement pressurizer is a like for like replacement and does not introduce any new components. The replacement pressurizer design utilizes Alloy 690 material for all components previously composed of Alloy 600 to mitigate primary water stress corrosion cracking. The replacement pressurizer was designed and fabricated in accordance with the ASME Section III, 1998 Edition through 2000 Addenda.

A design review of the PSL Unit 1 replacement pressurizer was performed as part of the EPU project. Details of the review are included in Section 2.2.2.7 of the PSL Unit 1 EPU LAR. The review concluded that the replacement pressurizer components meet the stress/fatigue analysis requirements of the ASME Code, Section III for EPU conditions and there is no change to fatigue usage values. As shown in Tables 4.3.1-1, 4.3.1-3, and 4.3.1-5, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 1 replacement pressurizer will remain less than unity during the SPEO.

The PSL Unit 2 pressurizer was designed and fabricated in accordance with the ASME Code Section III, 1971 Edition through Summer 1972. A design review of the PSL Unit 2 pressurizer was performed as part of the EPU project. Details of the review are included in Section 2.2.2.7 of the PSL Unit 2 EPU LAR. The review concluded that the pressurizer components meet the stress/fatigue analysis requirements of the ASME Code, Section III for EPU conditions and there is no change to fatigue usage values. As shown in Tables 4.3.1-2, 4.3.1-4, and 4.3.1-6, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 2 pressurizer will remain less than unity during the SPEO.

Reactor Vessel Internals

The PSL Unit 1 reactor vessel internals (RVI) components were designed to ensure that the stress levels and deflections were within an acceptable range. The allowable stress values for core support structures are not greater than those given in the May 1972 draft of Section III of the ASME Boiler and Pressure Vessel Code, Subsection NG, Appendix F, "Rules for Evaluation of Faulted Conditions."

During the 1983 PSL Unit 1 refueling outage, the RVI core support barrel (CSB) and thermal shield assembly were observed to be damaged. Four thermal shield support lugs were found to have become separated from the CSB and through-wall cracks were found in the CSB adjacent to the damaged lug areas. Corrective actions included permanent removal of the thermal shield and the CSB was repaired at the thermal shield support lug locations. Additional details regarding CSB damage and subsequent repairs can be found in PSL UFSAR Section 4.2.2.2.6 and SLRA Section 4.7.3. The damage to the PSL Unit 1 CSB and corresponding impact on fatigue was addressed in the original license renewal application. Specifically, the details of the as-repaired CSB middle cylinder fatigue analysis are provided in the FPL response to license renewal RAI 4.6.3-1 (Reference ML022890450). The fatigue analysis conservatively applied the 40-year design cycles, which bound the projected cycles for the 60-year PEO. The CSB middle cylinder fatigue analysis for the PEO resulted in a limiting CUF of 0.58, which is below the allowable value of 1.0.

A design review of the PSL Unit 1 RVI was performed as part of the EPU project. Details of the review are included in Section 2.2.3 of the PSL Unit 1 EPU LAR. The results of the review demonstrated that the PSL Unit 1 RVI components are structurally adequate for the EPU conditions and the fatigue usage factors were less than 1.0. A summary of the stresses versus allowables and the corresponding fatigue usage factors is given in EPU LAR Table 2.2.3-1. As shown in Tables 4.3.1-1, 4.3.1-3, and 4.3.1-5, the 40-year design cycles (CLB cycles) bound the projected cycles for the SPEO. In addition, Westinghouse non-proprietary letter report LTR-SDA-20-104-NP (Reference 4.8.6) and proprietary report LTR-SDA-20-104-P (Reference 4.8.7), provide an additional fatigue evaluation of the PSL Unit 1 RVI which concludes the Unit 1 RVI fatigue analyses performed for the EPU remain applicable for the SPEO. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 1 RVI, including the CSB middle cylinder, will remain less than unity during the SPEO.

The PSL Unit 2 RVI were designed and fabricated in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code Section III, Subsection NG, 1971 Edition with Addenda through the Winter of 1973. A design review of the PSL Unit 2 RVI was performed as part of the EPU. Details of the review are included in Section 2.2.3 of the PSL Unit 2 EPU LAR. The results of the review demonstrated that the PSL Unit 2 RVI components are structurally adequate for the EPU conditions and the fatigue usage factors remain less than 1.0. A summary of the stresses versus the allowables and the corresponding fatigue usage factors is provided EPU LAR Table 2.2.3-1. As shown in Tables 4.3.1-2, 4.3.1-4, and 4.3.1-6, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Similar to PSL Unit 1, Westinghouse non-proprietary letter report LTR-SDA-20-104-NP and proprietary report LTR-SDA-20-104-P, provide an additional fatigue evaluation of the PSL Unit 2 RVI which concludes the RVI fatigue analyses performed for the EPU remain applicable for the SPEO. Therefore, the fatigue analyses and corresponding CUF for the PSL Unit 2 RVI will remain less than unity during the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The ASME Section III, Class 1 and ANSI B31.7, Class 1 fatigue analyses 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, including the loss of letdown flow transient, and ensure corrective action is taken prior to potentially exceeding fatigue design limits in accordance with 10 CFR 54.21(c)(1)(iii).

Table 4.3.1-1
St. Lucie Unit 1 Design Transients Included in Fatigue Monitoring Program

Transient	Cycle Limit (1)	Cycle Counts as of 12/31/19	80-Year Projection	Margin
Reactor Trip	400	58	106	73%
Plant Heat-up	500	78	143	71%
Plant Cooldown	500	77	141	71%
Pressurizer Heat-up	500	71	130	74%
Pressurizer Cooldown	500	71	130	74%
Primary Side Hydrostatic Test	10	1	3 (2)	70%
Secondary Side Hydrostatic Test	10	1	3 (2)	70%
Primary Leak Test	200	0	2	99%
Secondary Leak Test	200	1	3 (2)	98%
Loss of Secondary Pressure	5	0	2	60%
Pressurizer Spray	1500 (3)	296	597 (2)	60%
Inadvertent Auxiliary Spray	16	3	6	62%
Loss of Offsite Power (Loss of RCS Flow)	40	0	2	95%
Loss of Load	40	3	6	85%
Plant Loading, 5%/min.	15000	NC (4)	NC (4)	NA
Plant Unloading, 5%/min.	15000	NC (4)	NC (4)	NA
10% Step Load Increase	2000	NC (4)	NC (4)	NA
10% Step Load Decrease	2000	NC (4)	NC (4)	NA
Normal Plant Variations, +/- 100 psi, +/- 6ºF	1000000	NC (4)	NC (4)	NA
Primary Coolant Pump Starting/Stopping	4000	NC (4)	NC (4)	NA
Purification	1000	NC (4)	NC (4)	NA
Low Volume Control and Makeup	2000	NC (4)	NC (4)	NA
Boric Acid Dilution	8000	NC (4)	NC (4)	NA
Cold Feed Following Hot Standby	15000	NC (4)	NC (4)	NA
Actuation of Main or Auxiliary Spray	500	NC (4)	NC (4)	NA
Low Pressure Safety Injection, 40ºF Water into 300ºF Cold Leg	500	NC (4)	NC (4)	NA
Opening of Safety Injection Return Line Valves	2000	NC (4)	NC (4)	NA
Initiation of Shutdown Cooling	500	NC (4)	NC (4)	NA
Loss of Charging Flow	200	NC (4)	NC (4)	NA
Loss of Letdown Flow	50	NC (4)	NC (4)	NA
Regenerative Heat Exchanger Isolation Long Term	80	NC (4)	NC (4)	NA
Regenerative Heat Exchanger Isolation Short Term	40	NC (4)	NC (4)	NA
Loss of Feedwater Flow	8	NC (4)	NC (4)	NA
High Pressure Safety Injection, 40ºF Water into 550ºF Cold Leg	5	NC (4)	NC (4)	NA

Notes:

(1) Cycle Limits are from Section 3.9 of the PSL Unit 1 UFSAR.
(2) Projection was based on operating experience recorded in the recent period from the end of 2009 to the end of 2019 versus extrapolation of events recorded from the time of plant startup.
(3) The number of cycles for this event was increased from the original number reported in the UFSAR based on additional plant-specific analysis of the pressurizer spray line.
(4) NC - does not have cycles counted by the PSL Fatigue Monitoring AMP (Section B.2.2.1). Refer to Westinghouse Report LTR-SDA-II-20-032-NP for additional details.

Table 4.3.1-2
St. Lucie Unit 2 Design Transients Included in Fatigue Monitoring Program

Transient	Cycle Limit (1)	Cycle Counts as of 12/31/19	80-Year Projection	Margin
Reactor Trip	400	33	72	82%
Plant Heat-up	500	54	124 (3)	75%
Reduced Limit for 2B Steam Generator	120 (2)	21	91 (4)	24%
Plant Cooldown	500	53	123 (3)	75%
Reduced Limit for 2B Steam Generator	120 (2)	21	91 (4)	24%
Pressurizer Heat-up	500	49	107	78%
Pressurizer Cooldown	500	49	107	78%
Primary Side Hydrostatic Test	10	1	1	90%
Reduced Limit for 2B Steam Generator	1 (2)	1	1	0%
Primary Leak Test	200	2	5	97%
Reduced Limit for 2B Steam Generator	30 (2)	2	10 (4)	67%
Loss of Secondary Pressure	5	0	2	60%
Pressurizer Spray	1500 (5)	251	624 (3)	58%
Loss of Offsite Power (Loss of RCS Flow)	40	0	2	95%
Loss of Load	40	1	3	92%
Plant Loading, 5%/min.	15000	NC (6)	NC (6)	NA
Plant Unloading, 5%/min.	15000	NC (6)	NC (6)	NA
10% Step Load Increase	2000	NC (6)	NC (6)	NA
10% Step Load Decrease	2000	NC (6)	NC (6)	NA
Normal Plant Variations, +/- 100 psi, +/- 6ºF	1000000	NC (6)	NC (6)	NA
Purification and Boron Dilution	24000	NC (6)	NC (6)	NA
Operating Basis Earthquake	200	NC (6)	NC (6)	NA
Loss of Charging Flow	20	NC (6)	NC (6)	NA
Loss of Letdown Flow	50	NC (6)	NC (6)	NA
Isolation Check Valve Leaks	40	NC (6)	NC (6)	NA
Loss of Secondary Pressure	5	NC (6)	NC (6)	NA

Notes:
(1) Cycle Limits are from Section 3.9 of the UFSAR.
(2) Several component cyclic limits were affected by the fatigue re-evaluation of the 2B RSG primary-side components due to a foreign object (FO) damage event at the end of the SL2-21 refueling outage. Plant Heat-up and Cooldown cycle limits were reduced from 500 cycles to 120 cycles on the basis that 120 cycles remains bounding for a 60-year plant life and the Primary Side Hydrostatic Test cycle limit was reduced from 10 cycles to 1 cycle on the basis that this test was only performed once prior to installation and is not required to be repeated.
(3) Projection was based on operating experience recorded in the recent period from either the end of 2009 or, where applicable, from the start of the transient monitoring period to the end of 2019 versus extrapolation of events recorded from the time of plant startup.
(4) The cycle counts as of 12/31/19 and 80-year projected cycles for the transients specific to the 2B RSG reflect the cycles that occurred after the RSG installation.
(5) The number of cycles for this event was increased from the original number reported in the UFSAR based on additional plant-specific analysis of the pressurizer spray line.
(6) NC - does not have cycles counted by the PSL Fatigue Monitoring AMP (Section B.2.2.1). Refer to Westinghouse Report LTR-SDA-II-20-032-NP for additional details.

Table 4.3.1-3
Additional St. Lucie Unit 1 Design Transients Included in Fatigue Monitoring Program

Transient	Cycle Limit (1)	Cycle Counts as of 12/31/19	80-Year Projection	Margin
MSIV Spurious Closures after March 2013 Closure Event	10	0	2	80%

Notes:
(1) The PSL Fatigue Monitoring AMP tracks several transients that are not listed in the UFSAR. The 80-year cycle projection was performed for this transient in the event it would be needed for downstream evaluations.

Table 4.3.1-4
Additional St. Lucie Unit 2 Design Transients Included in Fatigue Monitoring Program

Transient	Cycle Limit (1)	Cycle Counts as of 12/31/19	80-Year Projection	Margin
Pressurizer Main or Auxiliary Spray Actuation with Delta T greater than 200°F	1000	203	443	55%
Pressurizer Spray Nozzle Cumulative Usage Factor	0.75	0.0212	0.0467(2)	93%
Permanent Cavity Seal Ring Experiences Reactor Heat-up and Cooldown	500	4	39	92%
Leak Tightness at Cold (torque cycles of 2B Steam Generator (primary manway)	30	9	24	20%

Notes:
(1) The PSL Fatigue Monitoring AMP (Section B.2.2.1) tracks several transients that are not listed in the UFSAR. The 80-year cycle projections were performed for these transients in the event they would be needed for downstream evaluations.
(2) Projection was based on operating experience recorded in the recent period from either the end of 2009 or, where applicable, from the start of the transient monitoring period to the end of 2019 versus extrapolation of events recorded from the time of plant startup.

Table 4.3.1-5
Additional St. Lucie Unit 1 Design Transients

Transient	Cycle Limit	80-Year Projection	Margin
Loading and Unloading Events			
Projected Cycles < 10%	NA	176	N/A
Projected Cycles ≥ 10 - < 30%	NA	159	N/A
Projected Cycles ≥ 30 - < 60%	NA	91	N/A
Projected Cycles ≥ 60 - 100%	NA	864	N/A
Total Cycles	15000	1290	91%
Charging and Letdown Isolation Events			
Loss of Charging Projection Summary	200	11	94%
Loss of Letdown Projection Summary	500 (1)	279	44%
Loss of Regenerative Heat Exchanger (Short-Term)	40	29	27%
Loss of Regenerative Heat Exchanger (Long-Term)	80	20	75%
Operational Basis Earthquake Events	200	2	99%
Safe Shutdown Earthquake Events	1	1	N/A
Purification (2)	1000	3504	61%
Boric Acid Dilution (2)	8000		

Notes:
(1) The number of cycles for this event was increased from the original number reported in the UFSAR based on additional plant-specific analysis of the charging nozzle and piping.
(2) The 80-year projections for the Purification and Boric Acid Dilution transients were grouped together since the transient curves in the design specifications are similar for these transients and the plant data was insufficient to differentiate between these transients. The margin was calculated based on the combined number of design cycles reported in the UFSAR.

Table 4.3.1-6
Additional St. Lucie Unit 2 Design Transients

Transient	Cycle Limit	80-Year Projection	Margin
Loading and Unloading Events			
Projected Cycles < 10%	NA	142	N/A
Projected Cycles ≥ 10 - < 30%	NA	91	N/A
Projected Cycles ≥ 30 - < 60%	NA	113	N/A
Projected Cycles ≥ 60 - 100%	NA	938	N/A
Total Cycles	15000	1284	91%
Charging and Letdown Isolation Events			
Loss of Charging Projection Summary	200	11	45%
Loss of Letdown Projection Summary	500 (1)	405	19%
Loss of Regenerative Heat Exchanger (Short-Term)	40	11	72%
Loss of Regenerative Heat Exchanger (Long-Term)	80	66	17%
Operational Basis Earthquake Events	200	2	99%
Safe Shutdown Earthquake Events	1	1	N/A
Purification and Boron Dilution	24000	1700	93%

Notes:
(1) The number of cycles for this event was increased from the original number reported in the UFSAR based on additional plant-specific analysis of the charging nozzle and piping.

4.3.2 Metal Fatigue of Non-Class 1 Components

TLAA Description:

As indicated in Table 3.2-2 of the Unit 1 UFSAR, non-Class 1 Quality Group B, C and D piping systems were originally designed in accordance with the following Code requirements:

PSL Unit 1
Minimum Code Requirements for Quality Group Piping Systems

Quality Group B	Quality Group C	Quality Group D
ANSI B31.7 Class II (1969 Edition)	ANSI B31.7 Class III (1969 Edition)	ANSI B31.1 or equivalent (1967 Edition)

Table 3.2-2 of the Unit 2 UFSAR indicates that non-Class 1 Quality Group B, C and D piping systems were originally designed in accordance with the following Code requirements:

PSL Unit 2
Minimum Code Requirements for Quality Group Piping Systems

Quality Group B	Quality Group C	Quality Group D
ASME Boiler and Pressure Vessel Code, Section III, Class 2	ASME Boiler and Pressure Vessel Code, Section III, Class 3	ANSI B31.1

Unlike the Class 1 piping codes, piping and components designed in accordance with the non-Class 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 codes first require 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 the table 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 the Units 1 and 2 non-Class 1 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, TLAA requiring evaluation for the SPEO.

TLAA Evaluation

The cyclic qualification of the piping per ASME Section III Class 2, ASME Section III Class 3, ANSI B31.7, and ANSI B31.1 Codes is based on the number of equivalent full temperature cycles and corresponding stress range reduction factor as listed in Table 4.3.2-1 below.

Table 4.3.2-1
Stress Range Reduction Factors

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 non-Class 1 piping systems 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 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 4.8.8) 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 PSL SLRA were initially screened for the TLAA associated with metal fatigue. PSL 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 PSL 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 4.3.2-2 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 4.3.2-2, indicate that 7000 thermal cycles will not be exceeded for 80 years of operation for all mechanical systems with the exception of the Unit 1 and 2 hot leg sample piping.

For the 60-year license renewal PEO, the RCS hot leg sample lines were determined to be limiting as these samples are taken on a daily basis. This equates to a 60 x 365 = 21,900 cycles for 60-years, exceeding 7000 thermal cycles; thus, this system warranted a separate calculation. For the PEO, plant specific stress calculations were developed for PSL Unit 1 and 2 using a stress range reduction factor of 0.8, which corresponded to the range of 14,000-22,000 thermal cycles. Acceptable stress results were obtained and justify a maximum number of cycles at 22,000 which bounds the 21,900 thermal cycles projected for the 60-year PEO.

For the 80-year SPEO, daily hot leg samples would equate to 80 x 365 = 29,200 cycles and exceeds the 22,000 thermal cycles justified for PEO. Therefore, plant specific analyses were developed for the 80-year SPEO for PSL Unit 1 and 2 using a stress range reduction factor (f) of 0.7, which corresponded to the range 22,000-45,000 thermal cycles. Acceptable stress results were obtained with f = 0.7 and justifies a maximum number of cycles at 45,000 for the SPEO. This bounds the 29,200 thermal cycles projected for the 80-year PEO for the PSL Units 1 and 2 RCS hot leg sample lines.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) and 10 CFR 54.21(c)(1)(ii)

The PSL Unit 1 and 2 non-Class 1 allowable stress calculations remain valid for the SPEO for all piping systems with the exception of the Unit 1 and 2 RCS hot leg sample lines. The Unit 1 and 2 RCS hot leg sample line allowable stress calculations results have been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(i) and 10 CFR 54.21(c)(1)(ii).

Table 4.3.2-2
Projected Number of Full Temperature Cycles

System Name	Conservative Basis for Cycle Projection	Projected Cycles for 80 years
Reactor Coolant	Reactor coolant system thermal and loading cycle limits are provided in Unit 1 UFSAR Section 5.2.1.2 and Unit 2 Table 3.9-3A. Plant heatup and cooldown limits are 500 cycles for both Unit 1 and 2. These thermal cycle limits are well below the fatigue limit of 7,000 cycles.	Less than 7,000 cycles
Chemical and Volume Control	Full temperature thermal cycles for the chemical and volume control system would occur only during plant heatup and cooldown, loss of charging, or loss of letdown flow events. The chemical and volume control system would need to be thermally cycled approximately every 4 days to reach the 7,000 fatigue cycle limit in the 80-year SPEO and this is not feasible based on actual plant operation.	Less than 7,000 cycles
Safety Injection	Safety injection system (including the shutdown cooling system) thermal and loading cycles would be consistent with the heatup and cooldown limits provided in Unit 1 UFSAR Section 5.2.1.2 and Unit 2 Table 3.9-3A. Plant heatup and cooldown limits are 500 cycles for both Unit 1 and 2. These thermal cycle limits are well below the fatigue limit of 7,000 cycles.	Less than 7,000 cycles
Sampling	For the 80-year SPEO, daily hot leg samples would equate to 80 x 365 = 29,200 cycles and exceeds the 22,000 thermal cycles justified for PEO. Therefore, plant specific analyses were developed for the 80-year SPEO for PSL Unit 1 and 2 using a stress range reduction factor (f) of 0.7. Acceptable stress results were obtained with f = 0.7 and justifies a maximum number of cycles at 45,000 for the SPEO. This exceeds the 29,200 thermal cycles assumed for the 80-year PEO for the PSL Units 1 and 2 RCS hot leg sample lines	Less than 45,000 cycles
Main Steam	Main steam system thermal and loading cycles would be consistent with the heatup and cooldown limits provided in Unit 1 UFSAR Section 5.2.1.2 and Unit 2 Table 3.9-3A. Plant heatup and cooldown limits are 500 cycles for both Unit 1 and 2. These thermal cycle limits are well below the fatigue limit of 7,000 cycles.	Less than 7,000 cycles
Feedwater	Feedwater system thermal and loading cycles would be consistent with the heatup and cooldown limits provided in Unit 1 UFSAR Section 5.2.1.2 and Unit 2 Table 3.9-3A. Plant heatup and cooldown limits are 500 cycles for both Unit 1 and 2. These thermal cycle limits are well below the fatigue limit of 7,000 cycles.	Less than 7,000 cycles
Auxiliary Feedwater	In accordance with plant administrative procedures, the steam driven auxiliary feedwater pumps are tested once per month. This equates to 12 x 80 = 960 start cycles. This leaves a margin of over 6000 additional thermal cycles to the 7000 cycle fatigue limit which is more than sufficient to cover for plant startups/shutdowns, plant trips, retests, etc.	Less than 7,000 cycles
Heater Drain & Vents	Heater drain and vent system thermal and loading cycles would be consistent with the heatup and cooldown limits provided in Unit 1 UFSAR Section 5.2.1.2 and Unit 2 Table 3.9-3A. Plant heatup and cooldown limits are 500 cycles for both Unit 1 and 2. These thermal cycle limits are well below the fatigue limit of 7,000 cycles.	Less than 7,000 cycles

Table 4.3.2-2
Projected Number of Full Temperature Cycles

System Name	Conservative Basis for Cycle Projection	Projected Cycles for 80 years
Condensate	Condensate system thermal and loading cycles would be consistent with the heatup and cooldown limits provided in Unit 1 UFSAR Section 5.2.1.2 and Unit 2 Table 3.9-3A. Plant heatup and cooldown limits are 500 cycles for both Unit 1 and 2. These thermal cycle limits are well below the fatigue limit of 7,000 cycles.	Less than 7,000 cycles
Auxiliary Steam	Conservatively assuming the auxiliary steam system is thermally cycled once per week over the 80-year SPEO results in 4160 cycles which is less than the 7000 cycle limit.	Less than 7,000 cycles
Turbine	The main steam and turbine system thermal and loading cycles would be consistent with the heatup and cooldown limits provided in Unit 1 UFSAR Section 5.2.1.2 and Unit 2 Table 3.9-3A. Plant heatup and cooldown limits are 500 cycles for both Unit 1 and 2. These thermal cycle limits are well below the fatigue limit of 7,000 cycles.	Less than 7,000 cycles
Steam Generator Blowdown	Per Section 9.2.9 and Section 10.4.8 of the Unit 1 and 2 UFSARs, respectively, the steam generator blowdown system is normally in continuous operation. Conservatively assuming the system is isolated once per week over the 80-year SPEO results in 4160 cycles which is less than the 7000 cycle limit.	Less than 7,000 cycles
Radiation Monitoring	Per Section 12.2.4 and 12.3.4.2.3.1 of the Unit 1 and 2 UFSARs, respectively, the containment radiation monitoring system is normally in service while the containment air temperature is maintained below 120º. The system would only see elevated temperatures if operation and monitoring is required following a design basis accident. Therefore, full thermal cycles over the 80-year SPEO would be significantly less that the 7000 thermal cycle limit.	Less than 7,000 cycles
Hydrogen Sampling	Per Section 6.2.5.2.3 and Section 6.2.5.2.1 of the Unit 1 and 2 UFSARs, respectively, the containment hydrogen sampling system is normally isolated and placed in service by manual operator action from the control room following a design basis accident. Therefore, full thermal cycles over the 80-year SPEO would be significantly less that the 7000 thermal cycle limit.	Less than 7,000 cycles
Diesel Generator	In accordance with plant administrative procedures , the diesel generators are started monthly on a staggered test basis (or once every 2 months for each Unit's diesel generator. Conservatively assuming start once per month equates to 12 x 80 = 960 start cycles. This leaves a margin of over 6000 additional thermal cycles to the 7000 cycle fatigue limit which is more than sufficient to cover for other less frequent surveillance tests, retests, etc.	Less than 7,000 cycles

4.3.3 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_{en}) 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. Any additional limiting locations are identified through an environmentally-assisted fatigue (EAF) screening evaluation. The EAF screening process evaluates existing CLB fatigue usage values for the ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 equipment and piping components, to determine the lead indicator (also referred to as sentinel) locations for EAF.

TLAA Evaluation

In the EAF screening process, all of the applicable PSL Units 1 and 2 ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 component locations that are susceptible to EAF were reviewed and categorized by component. The goal of the EAF screening process was to eliminate locations for which environmental conditions are not a concern and provide a list of leading locations, which require further evaluation. Specifically, the following PSL Units 1 and 2 ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 components were considered in the EAF screening evaluation:

1. Equipment components
    - Reactor vessels including the replacement closure heads
    - Control element drive mechanisms
    - Pressurizers
    - Reactor coolant pumps
    - Steam generators (primary side)
2. Piping components
    - Reactor coolant loop piping
    - Auxiliary piping systems
        - Pressurizer surge piping
        - Pressurizer spray piping
        - Pressurizer safety and relief valve piping
        - RCS letdown and drain piping
        - Charging piping

- Safety injection piping
- Shutdown cooling piping

In order to perform the EAF screening process, all of the Class 1 reactor coolant pressure boundary piping and equipment components in scope that are susceptible to EAF must be reviewed and categorized into common groups for the purpose of identifying sentinel locations for EAF consideration. These sentinel locations are meant to supplement the locations identified in NUREG/CR-6260, resulting in a comprehensive list of plant-specific sentinel locations for EAF consideration. The EAF screening process compares components within each system on the bases of common transients and common stress analysis methods to determine the most limiting locations.

A total of four (4) vendors were responsible for performing the detailed EAF evaluations for PSL Units 1 and 2. The vendors were selected based upon those who own the specific component fatigue analysis of record. The vendors that performed the detailed EAF evaluations include Westinghouse, BWXT Canada, Framatome, and Structural Integrity. The methodology and the results used by each of the vendors are included in the following proprietary and non-proprietary reports:

a) Westinghouse – refer to Westinghouse Report LTR-SDA-II-20-31-NP, Rev. 2 (Non-Proprietary) and Westinghouse Report LTR-SDA-II-20-31-P, Rev. 2 (Proprietary), References 4.8.9 and 4.8.10, respectively,

b) BWXT Canada – refer to BWXT Report MSLEF-SR-01-NP, Revision 0 (Non-Proprietary) and BWXT Report MSLEF-SR-01-P, Revision 0 (Proprietary), References 4.8.11 and 4.8.12, respectively,

c) Framatome – refer to Framatome Document No. 86-9329647-000, (Non-Proprietary) and Framatome Document No. 86-9329644-001, (Proprietary), References 4.8.13 and 4.8.14, respectively, and

d) Structural Integrity Report No. 2001262.403, Revision 0, (Non-Proprietary), Reference 4.8.15.

The CUF_{en} values calculated by the vendors for each of the ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 component locations, with the exception of the PSL Units 1 and 2 pressurizer surge lines, are less than the ASME Code limit of 1.0, and are therefore acceptable. The effects of EAF on the intended functions of the component locations 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 (Section B.2.2.1) 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.

In lieu of additional analyses to refine the CUF_{en} for the PSL Units 1 and 2 pressurizer surge lines, PSL has selected aging management to address pressurizer surge line fatigue during the SPEO, consistent with what is currently done for the PEO. In particular, the potential for crack initiation and growth, including reactor water environmental effects, will be adequately managed during the SPEO by the plant-specific PSL Pressurizer Surge Line AMP (Section B.2.3.44). The surge line inspection approach for the PEO was submitted to the NRC for review in 2015, and was subsequently approved by the NRC in 2016 (Reference ML16235A138). The flaw tolerance analysis of the pressurizer surge lines establishes the inspection frequency for the Pressurizer Surge Line AMP. Details of the flaw tolerance analysis and inspection frequencies for the SPEO are provided in the Pressurizer Surge Line AMP (Section B.2.3.44).

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of environmentally-assisted fatigue on the intended functions of ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 component locations will be managed by the Fatigue Monitoring AMP (Section B.2.2.1) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

For the PSL Units 1 and 2 pressurizer surge lines, the effects of aging due to environmentally-assisted fatigue will continue to be managed by the Pressurizer Surge Line AMP (Section B.2.3.44) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.4 High-Energy Line Break Analyses

TLAA Description

The PSL Unit 1 high-energy line break (HELB) analysis methodology is discussed in Unit 1 UFSAR Section 3.6 and Appendices 3C and 3D. Section 3.6.1 of the UFSAR identifies those systems in which design basis piping breaks are postulated to occur. The UFSAR indicates that in analyzing the effects of a pipe rupture inside containment, breaks are assumed to occur at any location along the piping. Appendix 3C of the UFSAR discusses the HELB analysis of main steam and feedwater piping outside containment and states the design criteria employed for the design of restraints and their spacing are predicated on restraining the piping regardless of the location or orientation of postulated ruptures. Similarly, Appendix 3D of the UFSAR discusses the HELB analysis of other piping systems outside containment and states that break locations are assumed to occur at any location along the piping system. Since the HELB analysis criteria does not include any time-dependent assumptions, such as cumulative usage factor (CUF) or a fatigue based maximum allowable stress criterion, HELB is not considered a TLAA for Unit 1.

The PSL Unit 2 HELB analysis methodology is discussed in Unit 2 UFSAR Section 3.6 and indicates the criteria for pipe breaks inside containment has been postulated in accordance with Regulatory Guide 1.46, Protection Against Pipe Whip Inside Containment (May 1973) and pipe breaks outside containment followed the guidance provided in letters sent by A. Giambusso, AEC Directorate of Licensing, in December 1972. The methodology used to define break locations is further described in UFSAR Section 3.6.2 and indicates that both the CUF criterion (CUF > 0.1) and the maximum allowable stress criterion were used to determine break locations. Since both the CUF and maximum allowable stress methods are based on time-dependent fatigue design cycles, the determination of HELB break locations are considered TLAA for Unit 2.

TLAA Evaluation

As indicated in Section 4.3.1, the Unit 2 Class 1 reactor coolant piping was originally designed to the requirements of ASME Boiler and Pressure Vessel Code, Section III, Class 1, 1971 Edition through Winter 1972 Addenda (NSSS vendor supplied piping) and ASME Boiler and Pressure Vessel Code, Section III, Class 1, 1971 Edition through Winter 1973 Addenda (Architect/Engineer supplied piping). These Codes require a design analysis for the piping that addresses fatigue and establishes limits such that initiation of fatigue cracks is precluded. These 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. As discussed in Section 4.3.1 and Table 4.3.1-1, the original Unit 2 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses, corresponding CUFs, and Class 1 piping postulated HELB break locations remain valid for the SPEO.

Section 4.3.2 indicates that the Unit 2 non-Class 1 Quality Group B, C and D piping systems were originally designed in accordance with the requirements of the ASME Section III Class 2, ASME Section III Class 3, and ANSI B31.1 requirements, respectively. Section 4.3.2 further states that the cyclic qualification of the piping per these Codes is based on the number of equivalent full temperature cycles and corresponding stress range reduction factor. The evaluations for required stress reduction factors are considered implicit fatigue analyses because they are based on the number of fatigue cycles anticipated for the life of the component. Table 4.3.2-2 provides the results of the evaluation that was performed to determine a conservative number of projected fatigue cycles for 80 years of plant operation for piping systems in the scope of SLR and designed to these Codes. These projections indicate that the fatigue cycles limits for these piping systems will not be exceeded for the 80-year SPEO. Therefore, the implicit fatigue analyses and postulated HELB break locations for Unit 2 also remain valid for the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) and 10 CFR 54.21(c)(1)(iii)

The PSL Unit 2 ASME Section III, Class 1 fatigue calculations and postulated HELB break locations remain valid for the SPEO. To ensure the Class 1 piping postulated HELB break locations based on CUFs tied to fatigue design cycles remain valid for the SPEO, the Fatigue Monitoring (Section B.2.2.1) AMP will track cycles for the significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits. Therefore, the TLAA for Class 1 piping is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

The PSL Unit 2 non-Class 1 postulated HELB break locations remain valid for the SPEO. The results of the implicit fatigue analyses presented in Table 4.3.2-2 that are used to determine HELB break location demonstrate that the number of assumed thermal cycles will not be exceeded in 80 years of plant operation. Therefore, the TLAA for non-Class 1 piping is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

4.4 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRICAL 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 TLAA. 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 Environmental Qualification 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 Environmental Qualification Program that involve time-limited assumptions defined by the current operating term of 60 years have been identified as TLAA 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 lives, are not TLAA.

TLAA Evaluation

The PSL Environmental Qualification of Electric Equipment AMP described in Section B.2.2.3 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 (B.2.2.3) 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 4.8.16), in NUREG-0588, Revision 1, “Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment” (Reference 4.8.17), and in Regulatory Guide 1.89, Revision 1, “Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants” (Reference 4.8.18).

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 (B.2.2.3) 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 (B.2.2.3) 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 AMP 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 (B.2.2.3) 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 TLAA 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 (B.2.2.3) AMP will manage the aging effects of the electrical and instrumentation components associated with the EQ TLAA.

NUREG-2192 states that the staff evaluated the Environmental Qualification of Electric Equipment (B.2.2.3) AMP (10 CFR 50.49) and determined that it is an acceptable AMP 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.

<u>Component Reanalysis Attributes</u>

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 (B.2.2.3) 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.

<u>Analytical Methods</u>

PSL 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 Environmental Qualification 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 4.8.19). As thermal aging is governed by the ambient temperature to which the device is exposed, the Environmental Qualification of Electric Equipment (B.2.2.3) AMP conservatively assumes a normal ambient temperature of ≤ 120°F for areas inside containment (for Unit 1), and ≤ 115°F for areas inside containment (for Unit 2); and a normal ambient temperature of ≤ 104°F for areas outside containment (for both Units 1 and 2).

For additional conservatism, a temperature rise of 10°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, implemented in 2012 for both Units (EPU power level of 3020 MWt) (Reference ML12181A109 for Unit 1 and ML12235A463 for Unit 2). The staff verified that the normal operating temperatures due to EPU will continue to be bounded by the temperatures used in the PSL EQ analyses. Furthermore, the staff verified that the EPU post-accident peak temperature will continue to be bounded by the peak temperature used in the PSL EQ analyses.

Radiation Considerations - Due to EPU, the core power level increased from 2700 MWt to 3020 MWt. Analyzed core power is currently 3020 MWt which includes a 0.7% measurement uncertainty. This represents an increase of approximately 18.5 percent in core thermal power (over the initial power levels when the operating licenses were first issued – in Dec. 1976 for Unit 1 and in June 1983 for Unit 2). The radiation EQ for SR 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. Certain specific motors for Unit 1 required the installation of metallic shielding and certain RTD components on Unit 2 required replacement to meet the EPU radiation evaluation. The impact of Extended Power Uprate (EPU power level of 3020 MWt) on the PSL normal gamma and neutron radiation levels for inside containment was evaluated. The normal radiation dose for outside containment did not change due to EPU conditions. The normal neutron radiation doses for locations outside containment are insignificant considering the shielding provided by the containment structure. The normal 80-year total integrated radiation doses inside containment vary with the specific area.

Thus, 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 (B.2.2.3) 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 (B.2.2.3) 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 (B.2.2.3) 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 PSL 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 (B.2.2.3) 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 (B.2.2.3) 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 in accordance with 10 CFR 54.21(c)(1)(iii).

4.5 CONCRETE CONTAINMENT TENDON PRESTRESS

The PSL Units 1 and 2 containments utilize a reinforced concrete design without the use of prestressed tendons. Therefore, loss of tendon prestress is not applicable for the PSL containment shield buildings.

4.6 CONTAINMENT LINER PLATE, METAL CONTAINMENTS AND PENETRATIONS FATIGUE

Metal Containment Fatigue

TLAA Description

As stated in Sections 3.8.2.1.5 and 3.8.2.6.1 of the PSL Unit 1 and 2 UFSARs, respectively, the containment vessels are fabricated from welded ASME-SA 516 Grade 70 steel plates to provide an essentially leak-tight barrier. Design criteria applied to the steel containment vessels assure that the specified leak rate is not exceeded under the design basis accident conditions. The PSL Unit 1 containment vessel is designed in accordance with the 1968 Edition of ASME Boiler and Pressure Vessel Code, Section III (Reference 4.8.20) and the PSL Unit 2 containment vessel is designed in accordance with the 1971 Edition of ASME Boiler and Pressure Vessel Code, Section III (Reference 4.8.21). The CLB for the PSL Unit 1 and 2 containment vessels includes fatigue waiver evaluations that preclude the need for a detailed fatigue analysis. Fatigue waivers that consider transient cycles which occur over the life of the plant constitute TLAAs.

TLAA Evaluation

The original PSL Unit 1 and 2 design demonstrated that the fatigue waiver was applicable to both containment vessels. The fatigue waiver for the PSL Unit 1 and 2 containment vessels remain valid through the 80-year SPEO since the service loading of the vessels meet all the following six fatigue waiver conditions of Section III of the ASME Code.

1) Atmospheric to operating pressure cycles

   The Unit 2 containment vessel allowable stress is:

   - Sa= 3Sm = 3 x 19,300 psi = 57,900 psi

   which corresponds to approximately 3000 allowable cycles (Reference 4.8.21) and is bounding for both units. As stated in Section 4.3.1, the maximum allowable number of heatup/cooldown cycles for the PSL Unit 1 and 2 RCS is 500. Therefore, this fatigue waiver requirement is satisfied for both PSL Unit 1 and 2 for the SPEO.

2) Normal service pressure fluctuations

   The allowable pressure fluctuation (design pressure x (1/3)(S/Sm)) is:

   - 39.6 psig x (1/3)(13,000 psi /17,500 psi) = 9.81 psi for the Unit 1 containment vessel and,

   - 44 psig x (1/3)(13000 psi / 19,300 psi) = 9.88 psi for the Unit 2 containment vessel

The normal operating pressure of both containment vessels is essentially constant with little and no fluctuation. Thus, the normal service pressure fluctuation requirement is satisfied.

The significant pressure fluctuations are from integrated leak rate tests (ILRT) of the containment vessels which are typically performed every 15 years. Conservatively assuming 100 ILRTs for the 80-year SPEO, the bounding PSL Unit 2 allowable pressure fluctuation is:

- 44 psig x (1/3)(190,000 psi / 19,300 psi) = 144 psi > 44 psig

Therefore, this fatigue waiver requirement is satisfied for both PSL Unit 1 and 2 for the SPEO.

3) Temperature difference - startup and shutdown

The maximum temperature range shall not exceed Sa/(2Eα), which is:

- 110,000 / ((2)(30 x 10^{6})(6.44 x 10^{-6})) = 284°F for Unit 1, and
- 110,000 / ((2)(30 x 10^{6})(6.57 x 10^{-6})) = 279°F for Unit 2

Since the PSL maximum temperature range of 110°F (150°F to 40°F) is smaller than Sa/(2Eα), this fatigue waiver requirement is satisfied for both PSL Unit 1 and 2 for the SPEO.

4) Temperature difference - normal service

The normal operating temperature of PSL containment vessels is approximately 110°F to 125°F. This temperature fluctuation of 15ºF is considered negligible. Thus, this fatigue waiver requirement is satisfied for both PSL Unit 1 and 2 for the SPEO.

5) Temperature difference - dissimilar materials

During normal operation, components fabricated from materials of differing elastic modulus and/or coefficient of thermal expansion may not fluctuate more than (Sa)/[2(E1α1 - E2α2)]. The limiting dissimilar metal combination for the PSL containment vessels is carbon steel and SS. This range is therefore:

- 13,000 / ((2)(30.5)(7.3 x 10^{-6}) – (27.4)(6.25 x 10^{-6})) = 126.5 °F

This is greater than the 15ºF range of temperature fluctuation during normal operation of units. Thus, this fatigue waiver requirement is satisfied for both PSL Unit 1 and 2 for the SPEO.

6) Mechanical loads

The only mechanical load fluctuation on the containment vessels associated with normal operation occurs at the piping penetrations. The PSL piping penetrations are qualified for 7000 cycles (Appendix 3G of the Unit 1 UFSAR and Section 3.8 of the Unit 2 UFSAR). The Sa at 7000 cycles is approximately 43,000 psi (Reference 4.8.20, Fig. N-415 (a) and Reference 4.8.21, Fig. I-9.0). This value is much greater than allowable membrane stress values (17,500 psi for the Unit 1 containment vessel and 19,300 psi for the Unit 2 containment vessel). Therefore, this fatigue waiver requirement is satisfied for both PSL Unit 1 and 2 for the SPEO

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

Based on the above evaluation, the fatigue waiver for the PSL Unit 1 and 2 containment vessels remain valid through the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

Penetrations Fatigue

TLAA Description

In accordance with Section 4.5.2 of NUREG-1779, the PSL Unit 1 and 2 containment penetrations are specified to withstand a lifetime total of 7000 cycles of expansion and compression due to maximum operating thermal expansion, and 200 cycles of other movements (seismic motion and differential settlement).

The PSL Unit 1 and 2 containment penetrations are categorized as follows:

- Type I - those which must accommodate considerable thermal movements (hot penetrations)
- Type II - those which are not required to accommodate thermal movements (low temperature penetrations)
- Type III - those which must accommodate moderate thermal movements (semi-hot penetrations)
- Type IV - containment sump recirculation suction lines
- Type V - fuel transfer tubes

Each of the above items require evaluation for the 80-year SPEO.

TLAA Evaluation

Type I and Type III Penetrations

The thermal fatigue design limits of the Type I and Type III containment penetration bellows (7,000 thermal cycles) are bounded by the thermal fatigue design limits of their associated piping systems. The piping systems associated with Type I and Type III penetration bellows have been evaluated in Sections 4.3.1 and 4.3.2 and found acceptable for the SPEO. The 200 cycles of differential settlement and seismic motion are also bounding for the SPEO since they are not susceptible to any significant differential settlement they have not been subjected to any seismic loading to date.

Type II, Type IV, and Type V Penetrations

Type II penetrations are low temperature penetrations, Type IV penetrations are only used in post-accident scenarios, and Type V penetrations are the Unit 1 and 2 fuel transfer tubes. As such, these penetrations are not exposed to large thermal loads or thermal movements; however, these penetrations were conservatively designed for 7,000 cycles of expansion and compression due to operating thermal expansion and 200 cycles of differential settlement and seismic motion. The 7000 thermal cycles and 200 cycles of differential settlement and seismic motion for Type II, Type IV, and Type V penetrations are bounding for the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The existing fatigue analyses for the PSL Unit 1 and 2 containment piping penetrations have been evaluated and determined to remain valid for the SPEO, in accordance with 10 CFR 54.21(c)(1)(i).

4.7 OTHER PLANT-SPECIFIC TLAAs

4.7.1 Leak-Before-Break of Reactor Coolant System Piping

TLAA Description

The Combustion Engineering Owners Group (CEOG) performed the leak-before-break (LBB) evaluation CEN-367-A (Reference 4.8.22, for the PSL Units 1 and 2 primary loop piping in February 1991 along with other Combustion Engineering designed nuclear steam supply systems of similar layouts. The LBB evaluation was updated in 2009 for Unit 1 and in 2010 for Unit 2 as part of the extended power uprate (EPU) project. In comparing the revised plant-specific loads for the EPU to the evaluation performed in CEN-367-A, it was concluded that the PSL Unit 1 and 2 RCS hot and cold leg piping remained qualified for the LBB under EPU conditions and that CEN-367-A remained applicable for both Unit 1 and 2.

Considering the current PSL Unit 1 and 2 LBB analysis includes a postulated crack stability analysis that is related to the period of plant operation, the primary loop piping LBB analysis is a TLAA for SLR.

TLAA Evaluation

WCAP-18617-NP and WCAP-18617-P (References 4.8.23 and 4.8.24) performed the LBB evaluation for PSL Units 1 and 2 assuming an 80-year plant life. The analysis documented the plant-specific geometry, loading, and material properties used in the fracture mechanics evaluation.

The PSL Units 1 and 2 primary loop piping is constructed from carbon steel (SA-516-70) material with SS cladding. The carbon steel cold leg piping is connected to the RCP suction and discharge nozzles and the four nozzle safe-ends contain A351-CF8M CASS material and Alloy 82/182 dissimilar weld material. The A351-CF8M material is susceptible to the thermal aging at the reactor operating temperatures the Alloy 82/182 weld material is susceptible to primary water stress corrosion cracking (PWSCC).

Based on NUREG/CR-4513 (Reference 4.8.25) the fracture toughness correlations used for the full aged condition is applicable for plants operating at ≥ 15 EFPY for the A351-CF8M materials. For the 80-year SPEO, the materials will thermally age. Therefore, the use of the fracture toughness correlations is applicable for the fully aged or saturated condition of the PSL Units 1 and 2 RCP nozzle safe-ends.

WCAP-18617-NP and WCAP-18617-P include 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 piping material Certified Materials Test Reports (CMTRs).

The fatigue crack growth analysis originally included in CEN-367-A used generic design basis transient cycles that envelope the projected 80-year transient cycles for PSL Units 1 and 2 to calculate the crack growth. Therefore, the generic fatigue crack growth analysis results are representative of the PSL Unit 1 and 2 fatigue crack growth and are applicable for the 80-year SPEO.

WCAP-18617-NP and WCAP-18617-P justify the elimination of RCS 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 piping system and controls on reactor coolant chemistry, temperature, pressure, and flow during normal operation. Alloy 82/182 welds are present at the PSL Unit 1 and Unit 2 RCP suction and discharge nozzles. The Alloy 82/182 welds are susceptible to PWSCC and have been conservatively evaluated to consider the effects of PWSCC.

b. For global failure mechanisms, all locations are evaluated using the limiting material properties. For local failure mechanisms, all locations are evaluated using the A351-CF8M cast SS material properties which present a limiting condition due to the thermal aging effects.

c. Evaluation of the RCS piping considering the thermal aging effects for the 80-year SPEO and the use of the most limiting fracture toughness properties ensures that each material profile is appropriately bounded by the LBB results presented in WCAP-18617-NP and WCAP-18617-P.

d. Water hammer should not occur in the RCS piping because of system design, testing, and operational considerations.

e. The effects of low and high cycle fatigue on the integrity of the primary piping are negligible.

f. Ample margin exists between the leak rate of small stable flaws and the capability of the PSL Unit 1 and 2 RCS pressure boundary leakage detection system.

g. Ample margin exists between the small stable flaw sizes of item (f) and larger stable flaws.

h. Ample margin exists in the material properties used to demonstrate end-of-service life (fully aged) stability of the critical flaws.

For the critical locations, flaws are identified that will be stable because of the ample margins described in f, g, and h above.

The LBB analysis results for the RCP suction and discharge nozzle safe-end locations are acceptable for A351-CF8M CASS material from thermal aging effect and for Alloy 82/182 dissimilar metal weld material from PWSCC effect. All the LBB criteria are satisfied. The results for the reactor coolant loop remaining locations not evaluated in WCAP-18617-NP and WCAP-18617-P remain bounded by the analysis of record, CEN-367-A.

WCAP-18617-NP and WCAP-18617-P demonstrates that the conclusions reached in CEN-367-A remain applicable to PSL Unit 1 and 2 and the dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis for the 80-year SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The analyses performed in WCAP-18617-NP and WCAP-18617-P 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 subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

4.7.2 Alloy 600 Instrument Nozzle Repairs

TLAA Description

Small bore Alloy 600 nozzles, such as pressurizer and RCS hot leg instrumentation nozzles in Combustion Engineering (CE) designed PWRs have developed leaks or partial through-wall cracks as a result of primary water stress corrosion cracking (PWSCC). The residual stresses imposed by the partial-penetration "J" welds between the nozzles and the low alloy or carbon steel pressure boundary components are the driving force for crack initiation and propagation.

PSL Units 1 and 2 have experienced instances of Alloy 600 instrument nozzle leakage over the design life of the plants. Therefore, repairs have been performed on the Unit 2 pressurizer and Unit 1 and 2 RCS hot leg Alloy 600 instrument nozzles by relocating the partial penetration attachment weld from the interior surface of the component to the outside surface of the component. (Note that the PSL Unit 1 pressurizer has been replaced with a design that no longer utilizes Alloy 600 instrument nozzles). Preventative repairs were also performed on this population of instrument nozzles to prevent future leakage.

The Alloy 600 instrument nozzle repairs were evaluated based on corrosion and fracture mechanics analyses justifying the acceptability of indications in the "J" weld based on a conservative corrosion rate and postulated flaw size and flaw growth. Considering these analyses are currently based upon 60-year assumptions, these Alloy 600 instrument nozzle repair analyses have been identified as TLAAs requiring evaluation for the SPEO.

TLAA Evaluation

Tables 4.7-2 1 and 4.7-2 summarize the Alloy 600 instrument nozzle repairs for PSL Units 1 and Unit 2, respectively. Note that there are two methods of repair indicated in the tables:

1) The Half Nozzle Repair - in the half nozzle repair technique, the Alloy 600 nozzle is cut outboard of the partial-penetration weld and replaced with a short Alloy 690 nozzle section that is welded to the outside surface of the pressure boundary component. This repair leaves a short section of the original nozzle attached to the inside surface with the "J" weld.

2) Sleeve Repair- in the sleeve repair technique, the entire Alloy 600 nozzle is removed by machining and the bore diameter is slightly enlarged. An alloy 690 nozzle is inserted into the bore and rolled into place. A sleeve is placed between the Alloy 690 nozzle and the bore. The end of the sleeve at the interior surface of the piping or the pressurizer is either roll expanded or welded to the interior surface of the piping or pressurizer.

Alloy 600 instrument nozzle repairs were evaluated based on fracture mechanics analysis justifying the acceptability of indications in the "J" weld based on a conservative postulated flaw size and flaw growth considering the applicable design cycles. The Alloy 600 instrument nozzle repair evaluation was performed based on the fracture mechanics analysis provided in Combustion Engineering Owners Group

(CEOG) Topical Report CE NPSD-1198-P (Reference 4.8.26) and WCAP-15973-P-A (Reference ML050700431).

Westinghouse letter report LTR-SDA-20-097-NP and LTR-SDA-20-097-P (References 4.8.27 and 4.8.28) reassess the Alloy 600 instrument nozzle repairs for the PSL Units 1 and 2 SPEO including the following topics, in accordance with the request in NRC Safety Evaluation related to WCAP-15973-P (Reference ML050180528):

a) Calculate the maximum bore diameter at the end of 80 years operation considering the carbon and low-alloy steel borated water corrosion to demonstrate that the limiting allowable bore diameters are not exceeded.

b) Reconcile that the fatigue crack growth and flaw stability evaluation in WCAP-15973-P remain valid for the 80 years operation of PSL Units 1 and 2 plants to demonstrate that the ASME code acceptance criteria for crack growth and crack stability are met for the rest of the plant life including the extended operation.

c) Provide acceptable bases and arguments for concluding that unacceptable growth of the existing flaw by stress corrosion into the vessels or piping is improbable.

A summary of these three assessment topics is provided below.

Carbon and Low-Alloy Steel Borated Water Corrosion Evaluations

The half nozzle repair leaves a small gap between the remnant of the original alloy 600 nozzle and the new alloy 690 nozzle. As a result, primary coolant (borated water) will fill the crevice between the nozzle remnant and new nozzle and be in contact with the pipe or the pressurizer wall. Since a crevice exists, the low alloy and carbon steels are exposed to borated water and corrosion could occur. For the half nozzle repair, the corrosion rate from WCAP-15973-P-A is determined to bound the corrosion rate of 1.20 mils per year (mpy) for PSL Unit 1 and 1.34 mpy for PSL Unit 2 based on the plant power generation data. The results of the corrosion assessment show that the repair bore diameter at the end of 80 years operation is below the limiting allowable diameter for all the design half nozzle repairs. Therefore, these repairs have acceptable component wall thickness for the 80-year SPEO.

For the sleeve repair, the end of the Alloy 690 sleeve at the interior surface of the piping or the pressurizer is either roll expanded or welded to the interior surface of the piping or pressurizer to eliminate corrosion of the carbon and low alloy steel by stopping the replenishment of borated water in contact with the carbon steel. Since the borated water confined in the tight crevice between the sleeve and the interior surface of the piping or pressurizer cannot be replenished, the crevice region will fill with corrosion products when corrosion occurs. The presence of corrosion products in the crevice will prevent access of the corrodent (borated water) to the carbon and low alloy steel, reducing the corrosion rate. Further corrosion will result in the crevice corrosion products becoming denser and less permeable to the primary coolant. Eventually, the corrosion process will stifle because the steel will become isolated from the coolant. The maximum repair bore diameter at the end of 80 years operation is below the limiting allowable diameter for all the sleeve repairs. Therefore, these repairs are also acceptable for 80-year SPEO.

Sections 5 of LTR-SDA-20-097-NP and LTR-SDA-20-097-P provide additional details of the borated water corrosion evaluations.

Carbon and Low Alloy Steel Fatigue Crack Growth and Flaw Stability

Fatigue crack growth evaluation for Alloy 600 instrument nozzle repairs were performed to bound all the CE PWRs in WCAP-15973-P-A. Calculations were performed assuming that a crack had propagated through the nozzle and associated weld metal and had reached the interface with the carbon or low alloy steel. The postulated flaws were subjected to anticipated (Level A/B) transients for the plant evaluation period to determine the final flaw size using the guidance outlined in ASME Code Section XI, Appendix A. The final flaw size was then used in subsequent flaw stability calculations. WCAP-15973-P-A provided the results of fatigue crack growth evaluations and crack stability analyses for pressurizer heater sleeves and instrument nozzles and hot leg piping nozzles, including the effects of the support skirt and pressurizer in-surges. The details of the calculation are in CN-CI-02-71 (Reference 4.8.29) and the results indicate that the ASME code acceptance criteria for crack growth and crack stability are met.

Sections 6 of letter reports LTR-SDA-20-097-NP and LTR-SDA-20-097-P reconciled the fatigue crack growth and flaw stability evaluation in WCAP-15973-P-A for the PSL Units 1 and 2 80-year SPEO. The design cycles used in the WCAP-15973-P-A fatigue crack growth analysis are conservative and bound the PSL Units 1 and 2 projected transient cycles for 80 years of operation. The geometry of instrument nozzle repair locations in PSL Units 1 and 2 are bounded by that analyzed in CNCI-02-71. The plant-specific pressurizer cooldown curves are also bounded by the profile analyzed in CN-CI-02-71. The review of the Charpy impact data for the plant specific pressurizer items along with the Charpy impact data and upper shelf energy (USE) for the reactor vessel items provided in FPL letter L-2014-252 (Reference ML14224A010) demonstrated that the PSL Unit 2 pressurizer lower shell and lower head is expected to exhibit USE well in excess of 70 ft-lb and is bounded by the analysis in CN-CI-01-71; the pressurizer lower head and lower shell flaw stability evaluation based on elastic-plastic fracture mechanics (EPFM) analysis in CN-CI-01-71 thus can be used to demonstrate the acceptability of the Alloy 600 nozzle repairs performed for the PSL Unit 2 pressurizer locations. Therefore, the conclusion from the fatigue crack growth and flaw stability analyses in WCAP-15973-P-A and CN-CI-02-71 remains valid for the 80-year SPEO. The ASME code acceptance criteria for crack growth and crack stability are also met for the SPEO.

Sections 6 of LTR-SDA-20-097-NP and LTR-SDA-20-097-P provide additional details of the fatigue crack growth and flaw stability evaluations.

Carbon and Low Alloy Steel Stress Corrosion Cracking Assessment

As discussed in WCAP-15973-P-A, cracks that may be present in Alloy 600 remnants left in place following a half-nozzle repair or cracks that may initiate after completion of the repair will not propagate by stress corrosion cracking (SCC) through the carbon or low alloy steel components. Plant chemistry reviews show that for both PSL Unit 1 and 2, typical contaminant concentrations for dissolved oxygen, halide ions and sulfate ions are maintained at less than 5 ppb. The very low primary side oxygen levels that result in corrosion potentials is well below the critical cracking potentials for the carbon or low alloy steel materials.

Therefore, the Alloy 600 instrument nozzle repairs implemented on PSL Unit 1 and Unit 2 are evaluated to be acceptable regarding corrosion, fatigue crack growth and flaw stability, and stress corrosion cracking for 80-year SPEO

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

Westinghouse reports LTR-SDA-20-097-NP and LTR-SDA-20-097-P addressed each of these topics as required by the NRC SE and determined that the conclusions reached in (CEOG) Topical Report CE NPSD-1198-P and WCAP-15973-P-A regarding Alloy 600 instrument nozzle repairs remain valid for the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

Table 4.7.2-1
PSL Unit 1 RCS Hot Leg Alloy 600 Instrument Nozzles Repair History

Instrument ID	Hot Leg A or B	Repair Date	Repair Method	Reason for Repair
PDT-1121D	B	2005	½ Nozzle Repair	Leakage
TE-1112HA	A	2005	½ Nozzle Repair	Preventative
TE-1112HB	A	2005	½ Nozzle Repair	Preventative
TE-1112HC	A	2005	½ Nozzle Repair	Preventative
TE-1112HD	A	2005	½ Nozzle Repair	Preventative
TE-1111X	A	2005	½ Nozzle Repair	Preventative
TE-1122HA	B	2005	½ Nozzle Repair	Preventative
TE-1122HB	B	2005	½ Nozzle Repair	Preventative
TE-1122HC	B	2005	½ Nozzle Repair	Preventative
TE-1122HD	B	2005	½ Nozzle Repair	Preventative
TE-1121X	B	2005	½ Nozzle Repair	Preventative
PDT-1111A	A	2005	½ Nozzle Repair	Preventative
PDT-1111B	A	2005	½ Nozzle Repair	Preventative
PDT-1111C	A	2005	½ Nozzle Repair	Preventative
PDT-1111D	A	2005	½ Nozzle Repair	Preventative
PDT-1121A	B	2005	½ Nozzle Repair	Preventative
PDT-1121B	B	2005	½ Nozzle Repair	Preventative
PDT-1121C	B	2005	½ Nozzle Repair	Preventative
RC-143	A	2005	½ Nozzle Repair	Preventative

Table 4.7.2-2
PSL Unit 2 RCS Hot Leg and Pressurizer (PZR) Alloy 600 Instrument Nozzles Repair History

Component Location	Instrument ID	Repair Date	Repair Method	Reason for Repair
PZR Upper Head Steam Space	A	1994	½ Nozzle Repair[(1)]	Linear Indications
PZR Upper Head Steam Space	B	1994	½ Nozzle Repair[(1)]	Linear Indications
PZR Upper Head Steam Space	C	1994	½ Nozzle Repair[(1)]	Leakage / Linear Indications
PZR Upper Head Steam Space	D	1994	½ Nozzle Repair[(1)]	Preventative
PZR Lower Head Water Space Head	RC-105	1995[(2)]	Sleeve Repair[(1)]	Preventative
PZR Lower Head Water Space Head	RC-130	1995	Sleeve Repair[(1)]	Preventative
PZR Side Shell Water Space Head	TE-1101	1995	Sleeve Repair[(1)]	Preventative
RCS Hot Leg RTD Nozzle	TE-1112HA	1989	Sleeve Repair[(1)(3)]	Preventative
RCS Hot Leg RTD Nozzle	TE-1111X	1989	Sleeve Repair[(1)(3)]	Preventative
RCS Hot Leg RTD Nozzle	TE-1122HC	1989	Sleeve Repair[(1)(3)]	Preventative
RCS Hot Leg RTD Nozzle	TE-1122HD	1989	Sleeve Repair[(1)(3)]	Preventative
RCS Hot Leg RTD Nozzle	TE-1121X	1989	Sleeve Repair[(1)(3)]	Preventative
RCS Hot Leg RTD Nozzle	TE-1112HB	2003	½ Nozzle Repair	Preventative
RCS Hot Leg RTD Nozzle	TE-1112HC	2003	½ Nozzle Repair	Preventative
RCS Hot Leg RTD Nozzle	TE-1112HD	2003	½ Nozzle Repair	Preventative
RCS Hot Leg RTD Nozzle	TE-1122HA	2003	½ Nozzle Repair	Preventative
RCS Hot Leg RTD Nozzle	TE-1122HB	2003	½ Nozzle Repair	Preventative
RCS Hot Leg Flow Nozzle	PDT-1121B	1995	Sleeve Repair	Leakage
RCS Hot Leg Flow Nozzle	PDT-1111A	1995	Sleeve Repair	Preventative
RCS Hot Leg Flow Nozzle	PDT-1111B	1995	Sleeve Repair	Preventative
RCS Hot Leg Flow Nozzle	PDT-1111C	1995	Sleeve Repair	Preventative

Component Location	Instrument ID	Repair Date	Repair Method	Reason for Repair
RCS Hot Leg Flow Nozzle	PDT-1111D	1995	Sleeve Repair	Preventative
RCS Hot Leg Flow Nozzle	PDT-1121A	1995	Sleeve Repair	Preventative
RCS Hot Leg Flow Nozzle	PDT-1121C	1995	Sleeve Repair	Preventative
RCS Hot Leg Flow Nozzle	PDT-1121D	1995	Sleeve Repair	Preventative
RCS Hot Leg Flow Nozzle	Sample Line	1995	Sleeve Repair	Preventative
PZR Heater Sleeves	30 Sleeves	2011	½ Nozzle Repair(1)	Preventative

Notes:

1. Nozzle welded to a nickel alloy weld pad.
2. This location was repaired again in 2018 with a similar design. The only difference is that the nickel alloy weld pad was changed from Alloy 600 equivalent to Alloy 690 equivalent weld metal.
3. Alloy 600 weld pad was used at the outer wall. Per [8], any Alloy 600 material at the outer wall of the repair is managed by the Alloy 600 inspection program and is beyond the scope of the evaluation in this calculation note.

4.7.3 Unit 1 Core Support Barrel Repairs

TLAA Description

During the 1983 PSL Unit 1 refueling outage, the RVI core support barrel (CSB) and thermal shield assembly were observed to be damaged. Four thermal shield support lugs were found to have become separated from the CSB and through-wall cracks were found in the CSB adjacent to the damaged lug areas. Corrective actions included permanent removal of the thermal shield and the CSB was repaired at the thermal shield support lug locations. Through-wall cracks were arrested with crack arrestor holes and non-through-wall cracks were machined out. The lug tear out areas were machined out and patched. The crack arrestor holes were sealed by inserting expandable plugs. Analysis of the CSB repairs was performed by the NSSS supplier to demonstrate that the repair patches and expandable plug design were acceptable for the remaining 40-year life of the plant consistent with ASME code allowable stresses.

In 1984, a post-repair inspection of the CSB area repairs was performed to verify proper installation of the plugs and to provide a baseline for comparison of data obtained during future inspections. A visual and mechanical inspection of the CSB was performed during the 1986 PSL Unit 1 refueling outage after one cycle of operation. The inspection report concluded that the CSB was in the same condition as it was during the baseline inspection and was acceptable for long-term service with only visual inspections of the repair locations required at 10-year intervals in the future. A 10-year inservice inspection was performed during the 1996 refueling outage, with emphasis placed on visual inspection of the CSB repair areas. No abnormal changes were observed in the CSB repair areas based on comparisons between the 1984 and 1986 inspections. Subsequent visual inspection of the CSB repair locations was performed in 2008 (Reference 4.8.30) and no anomalies were noted. During the 2018 CSB inspection, indications were observed on the core shroud and the outside diameter of the CSB, however no anomalies were noted regarding the CSB expandable plugs (Reference ML19044A636). The PSL Unit 1 CSB was inspected again in 2019 and the results of the inspection did not identify evidence of flaw growth or other anomalies and supported an inspection interval of up to 10 years from the Spring 2018 refueling outage (Reference ML20134J047).

For the original PSL license renewal, the PSL Unit 1 CSB analyses and follow-up inspections for the repaired CSB and the expandable plugs were screened against the six TLAA criteria and two specific elements of the repairs qualified as TLAAs; 1) fatigue analysis of the CSB middle cylinder; and 2) acceptance criteria for the CSB expandable plug preload based on irradiation induced stress relaxation. Note that fatigue of the CSB middle cylinder is addressed in Section 4.3.1.

Considering the analysis of the PSL Unit 1 CSB expandable repair plugs is related to the period of plant operation, the analysis is a TLAA for SLR.

TLAA Evaluation

The CSB repair plugs are of an expandable design that allows the plugs to be preloaded against the CSB. Preload is required to provide proper seating of the plugs and patches and to prevent movement of the plugs due to hydraulic drag loads. The original evaluation of plug design preload verified that the design preload was sufficient to accommodate normal operating hydraulic loads and thermal deflections for the original operating life of the plant.

The original CSB plug preload analysis was revised for the PSL Unit 1 PEO to consider increased 60-year end-of-life (EOL) fluence as an irradiation-induced relaxation input. The analysis concluded that all the repair plug flange deflection measurement readings were sufficient to meet the minimum required values and maintain the plugs' preload for the 60-year PEO.

For the 80-year SPEO, Westinghouse prepared non-proprietary letter report LTR-SDA-20-104-NP (Reference 4.8.31) and proprietary report LTR-SDA-20-104-P (Reference 4.8.32), which re-calculate the minimum plug-flange deflection requirements for the PSL Unit 1 CSB repair plugs using the 72 EFPY fluence. Additional information regarding the methodology used by Westinghouse and the detailed results of the CSB plug preload analysis are included in the Westinghouse non-proprietary letter report LTR-SDA-20-104-NP and proprietary letter report LTR-SDA-20-104-P.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The analysis performed in Westinghouse letter reports LTR-SDA-20-104-NP and LTR-SDA-20-104-P determined that the PSL Unit 1 CSB repair plug flange deflections are acceptable for 80 years of plant operation. Therefore, the CSB repair plug deflections have been projected through the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

4.7.4 Reactor Coolant Pump Flywheel Fatigue Crack Growth

TLAA Description

The RCP flywheels are discussed in Sections 5.5.5 and 5.4.1 of the PSL Unit 1 and 2 UFSAR, respectively. During normal operation, the RCP 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 RCP increase both the potential for failure and the kinetic energy. The aging effect of concern is fatigue crack initiation in the flywheel.

Considering the RCP flywheel probability analyses of failure are part of the Unit 1 and 2 current licensing basis and are used to support safety determinations, the analyses have been identified as TLAA requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation

The Unit 1 RCP flywheel crack growth calculation was determined to be a TLAA for the original PSL license renewal as discussed in Section 4.1.2 of NUREG-1779 (Reference ML032940205). In Section 5.5.5.3 of the Unit 1 UFSAR, the RCP flywheel crack growth calculation indicates that the number of starting cycles required to cause a reasonably small crack to grow to critical size is more than 100,000. For the 60-year period of extended operation (PEO), FPL indicated that the 100,000 RCP start cycles required to cause a crack to grow to critical size for Unit 1 is far greater than the number of start cycles for this time period.

As discussed in Section 4.1.2 of NUREG-1779, the Unit 2 RCP crack growth calculation was determined not to be a TLAA for the 60-year PEO as a review of the Unit 2 CLB did not identify or reference fatigue crack growth calculations for the flywheels. However, on October 9, 2019, FPL submitted letter L-2019-091 (Reference ML19282D338) requesting an amendment to the Renewed Facility Operating License NPF-16 for Unit 2. The proposed amendment modifies the Unit 2 Technical Specifications by revising the RCP flywheel inspection program requirements consistent with the conclusions and limitations specified in NRC safety evaluation (SE) of Topical Report SIR-94-080, Revision 1 “Relaxation of Reactor Coolant Pump Flywheel Inspection Requirements (Reference ML20013C086).

Topical Report SIR-94-080 established a technical basis for relaxing the three-year RCP flywheel inspection recommended in Regulatory Guide (RG) 1.14. The topical report postulates an initial flaw for the flywheels and performs a crack growth and stability analysis under the most severe environmental and loading conditions. The NRC issued a SE for SIR-94-080, concluding that (1) all RCP flywheels meet the proposed non-ductile fracture criteria and have adequate fracture toughness during their service periods, and (2) all flywheels (except Waterford 3) satisfy the excessive deformation criterion of RG 1.14. The staff’s conclusions were based on the fracture toughness (KIC) values reported in SIR-94-080 for participating plants, including PSL Unit 2. In the SE, the staff authorized the application of SIR-94-080 in requests to extend RCP flywheel inspections from three to ten years provided the licensee verify the reference temperature (RTNDT) for their RCP flywheels and demonstrate that the corresponding fracture toughness (KIC) values are equivalent to those reported in SIR-94-080. The SE further stated that for flywheels made of materials other than SA 053B and SA 508, the licensee must justify use of the 'fracture toughness (KIC) versus T-RNDT' curve in Appendix A of the ASME Section XI Code to derive their respective KIC values. On November 18, 2020, the NRC issued Amendment No. 205 (Reference ML20259A298) which modifies the Unit 2 Technical Specifications by revising the RCP flywheel inspection program requirements to be consistent with the conclusions and limitations specified in the NRC safety evaluation of Topical Report SIR-94-080 (Reference ML20013C086).

The FPL review of Topical Report SIR-94-008 for applicability to Unit 2 is included in the Reference ML19282D338 License Amendment Request (LAR) . Section 3.6 of the LAR discusses the impact of Topical Report SIR-94-080 on license renewal. The review indicates that the topical report conservatively assumes 4000 cycles of RCP startups and shutdowns in its analysis of fatigue crack growth rates. Therefore, the topical report was evaluated by FPL as a TLAA for the 60-year PEO. The evaluation of the RCP flywheel TLAA for Unit 2 stated that the projected lifetime occurrences of plant heatups and cooldowns is 500 cycles based on the original plant 40-year design life and that the RCPs are cycled when filling and venting the RCS prior to Unit start-up. Conservatively estimating three RCP start/stop cycles per fill and vent activity and a fill and vent activity for each heatup and cooldown results in (500 x 4) or 2000 RCP start/stop cycles the 60-year PEO, which is well within the 4000 cycles assumed in topical report SIR-94-080.

For the SPEO, since to 4000 RCP stop/start cycle limit for Unit 2 is more restrictive than the 100,000 stop/start cycle limit for Unit 1, the 4000 RCP stop/start limit will be evaluated for both units. The assumed 2000 RCP start/stop cycles determined for the Unit 2 60-year PEO above is also applicable to the 80-year SPEO. This conclusion is due to the fact that the 500 heatup and cooldown cycle limit for the 60-year PEO remain applicable for the 80-year SPEO for both PSL Unit 1 and 2 as discussed in Section 4.3.1 of this report.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The RCP flywheel fatigue crack growth analyses for PSL Units 1 and 2 have been demonstrated to remain valid through the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.7.5 Reactor Coolant Pump Code Case N-481

TLAA Description

The PSL RCPs are Byron-Jackson vertical, single bottom suction, horizontal discharge, centrifugal motor-driven pumps. The pump casings are fabricated from ASTM A-351, Grade CF-8M CASS material. In 1993, the Combustion Engineering (CE) Owners group performed ASME Code Case N-481 flaw evaluations for several CE NSSS fleet pumps, including the PSL Units 1 and 2 RCPs in the report CEN-412, Revision 2 (Reference 4.8.33). ASME Code Case N-481 allows visual inspections in lieu of volumetric inspections of the pump casing base metal and welds based on a fracture mechanics evaluation. The NRC received the CEN-412 report but did not approve it generically and requested that utilities retain a copy at site for future audits as needed (Reference ML17227A644). As indicated in Section 3.1.5.2.1 of NUREG-1779, the NRC accepted the use of ASME Section XI IWB in-service inspection program to manage the reduction of fracture toughness for the PSL RCP CASS components for the first license renewal.

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, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)." Specifically, GALL-SLR AMP XI.M12 provides an allowance for continued use of flaw tolerance evaluations performed as part of implementation of ASME 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 ASME Code Case N-481 implementation remains bounding and applicable for the subsequent license renewal (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, Westinghouse performed a reconciliation analysis for the PSL evaluation completed in CEN-412. The latest piping loads and 80-year design transients and cycles were considered for the reconciliation. The fracture toughness evaluated in CEN-412 was based on NUREG-4513, Revision 0 (Reference 4.8.34). Since then, Revision 1 and Revision 2 of NUREG/CR-4513 have been published (References 4.8.35 and 4.8.36, respectively), and therefore, a confirmatory check is performed for the PSL RCP casings per NUREG/CR-4513 Revision 1 and 2. For the fatigue crack growth evaluation, PSL considered crack growth rates based on older industry accepted models as discussed in Section 5.1 of CEN-412. For the SLR scope, a comparison to the more recently accepted fatigue crack growth rates were considered for stainless steel in an air environment from Appendix C of the ASME Section XI code, with a PWR environment factor of 2 applied, in accordance with Reference 4.8.37.

As discussed in CEN-412, the calculated RCP casing material fracture toughness provides a basis for calculating the end-point crack size limits for the two failure modes related to thermal embrittlement: non-ductile propagation and ductile tearing.

The third criterion for establishing endpoint crack size is based on the flow stress of the material. Therefore, an end-point crack size was determined by these three criteria for SLR:

1. The crack becomes unstable against non-ductile propagation.
2. The crack becomes unstable against ductile tearing.
3. The remaining ligament cannot carry its original loading, based on its flow stress.

Acceptance criteria are based on ASME Section XI IWB-3600 [8].

Westinghouse reconciliation reports LTR-SDA-20-099-NP and LTR-SDA-20-099-P (References 4.8.38 and 4.8.39) were performed for the PSL RCP casings for the 80-year SPEO. The fatigue crack growth evaluations for the PSL RCP casings were reconciled for the 80-year SLR operation in Section 7.1 of the report and the current ASME Section XI crack growth rate. Section 7.2 of the report updates the fracture toughness for the RCP casings in accordance with NUREG/CR-4513, Revisions 1 and 2. As discussed in CEN-412 and Section 7.2, since the applied $K_I < K_{Jc}$, the stability against ductile tearing criterion is satisfied, and the only crack growth mechanism is related to fatigue cycles. Section 7.3 of the report evaluated the critical flaw sizes and acceptable period of operation based on non-ductile propagation, ductile tearing, and flow stress limit.

The conclusions in CEN-412 remain valid for 80-year SLR operation. A postulated initial flaw depth of 8% wall thickness will grow to 25% in about 110 years while satisfying the non-ductile propagation and ductile tearing criteria of $K_I < K_{Jc}$. The postulated flaw will continue to grow until reaching the critical flaw size of 38%, limited by the flow stress in about 130 years.

Therefore, the PSL Units 1 and 2 RCP casings meet the material criteria in ASME Code Case N-481 for waiving volumetric examinations of cast austenitic pump casings. A postulated 25% thickness reference flaw will remain stable under governing design, emergency, and faulted conditions stresses. All calculated endpoint (critical) flaw depths are greater than the 25% thickness reference flaw postulated in ASME Code Case N-481. Based on this evaluation, in-service volumetric examinations of these RCP casings are not necessary for the 80-year SLR period of operation. However, visual (VT-3) examinations of casing inside surfaces, to the extent practical, are prudent whenever an RCP is disassembled for maintenance. The PSL Units 1 and 2 RCP casing integrity is shown to be retained for a total of 130 years from initial operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

Reconciliation reports LTR-SDA-20-099-NP and LTR-SDA-20-099-P determined that the conclusions reached in CEN-412 regarding RCP flaw tolerance evaluations to address thermal aging as part of implementation of ASME Code Case N-481 remain valid for the SPEO, in accordance with 10 CFR 54.21(c)(1)(i).

4.7.6 Crane Load Cycle Limits

TLAA Description

A review of design specifications for cranes within the scope of SLR was performed to identify those cranes that comply with Crane Manufacturers Association of America Specification 70 (CMAA-70) (Reference 4.8.40) 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

The cranes considered to be a TLAA are those in compliance with NUREG-0612 (Reference 1.6.18) and in the scope of SLR for their lifting function. The NUREG-0612 cranes are documented in PSL Unit 1 UFSAR Section 9.6.2 and PSL Unit 2 UFSAR Table 9.6-1. The following cranes comply with NUREG-0612 and are included in scope of SLR for their lifting function:

PSL Unit 1

- Reactor building polar crane
- Intake structure bridge crane
- Spent fuel cask handling crane
- Auxiliary telescoping jib crane
- Refueling machine 1-ton hoist
- Fuel pool bulkhead monorail
- Turbine building gantry crane

PSL Unit 2

- Charging pump A, B, and C monorails
- Turbine building gantry crane
- Reactor polar crane
- Auxiliary telescoping jib crane
- Refueling machine and hoist
- Fuel transfer machine
- Spent-fuel handling machine
- Refueling canal bulkhead monorail
- Cask storage pool bulkhead monorail
- Spent fuel cask handling crane
- Diesel generator monorails
- Intake structure bridge crane

The PSL Unit 1 cranes were designed in accordance with Specification 61 of the Electrical Overhead Crane Institute (EOCI Specification 61) (Reference 4.8.41). Although not originally in accordance with CMAA-70, the original design of the PSL Unit 1 cranes meets CMAA-70 requirements. In Section 4.6.2 of NUREG-1779, the NRC staff concluded that the Unit 1 cranes meet or exceed CMAA-70 criteria. The

PSL Unit 1 spent fuel cask handling crane was replaced in 2003 and the replacement crane was designed in accordance with CMAA-70.

The PSL Unit 2 cranes comply with the applicable design requirements of ANSI B30.2, CMAA-70, and CMAA-74 as stated in Section 9.6.3.7 of the PSL Unit 2 UFSAR.

The PSL Units 1 and 2 cranes are used primarily during refueling outages. Occasionally cranes make lifts at or near their rated capacity; however, most crane lifts are substantially less than their rated capacity. Based on their historical and projected usage, the PSL Units 1 and 2 spent fuel handling machines make the most lifts at or near their rated capacities. Because the PSL Units 1 and 2 spent fuel handling machines went into service in 1976 and 1983, respectively, and both units began doing full-core offloads after 2000, the PSL Unit 2 spent fuel handing machine is projected to be subjected to more full-core offloads than the PSL Unit 1 spent fuel handling machine during their respective 80-year lives. Therefore, the PSL Unit 2 spent fuel handling machine will make the most lifts at or near its rated capacity and is bounding for the crane load cycle analysis.

CMAA-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-70 (1975), Table 3.3.3.1.3-1 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 in CMAA-70 (1975), Section 70-2, Crane Service Classification, is Class A1 Standby Service, which is defined as:

> "This service class covers cranes used in installations such as powerhouses, public utilities, turbine rooms, motor rooms and transformer stations, where precise handling of valuable machinery 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-70, the applicable service class for the PSL cranes, including the PSL Unit 2 spent fuel handling machine is Class A1.

Table 3.3.3.1.3-1 of CMAA-70 (1975) states that a range of load cycles from 20,000 to 100,000 is applicable for cranes in Service Class A1 service thus establishing the envelope for the acceptable number of load cycles for this TLAA.

The spent fuel handling machines are used primarily to move fuel assemblies for refueling and cask loading operations and are subject to the most loading cycles at or near their rated capacity.

After receipt of the renewed operating licenses in 2003, PSL Units 1 and 2 transitioned from offloading the full core once every ten years to offloading the full core every refueling outage. To account for these additional lifts, a conservative assumption was be made that full core offloads began in 2000. The 80-year load cycle calculation makes the following assumptions and results are summarized in Tables 4.7.6-1 and 4.7.6-2:

- 217 fuel assemblies (FAs) in the reactor core
- 1/3 of the core offloaded every refueling outage up to year 2000 (73 fuel assemblies)
- Full core offload once every 10 years up to year 2000
- Full core offload at every refueling outage following year 2000
- 1/3 of the core is replaced with new fuel each fuel cycle and this new fuel is loaded into the spent fuel pool prior to refueling the reactor (73 fuel assemblies)
- Core offload includes reload
- Cask storage loading campaigns will eventually offload all FA's used during the life of the plant

Table 4.7.6-1
Crane Load Cycles

Handling Event	Refueling Cycles	Fuel Assemblies Lifted Per Cycle	Total Load Cycles (80 years)
Full core offload/reload (prior to 2000)	2	434	868
Partial (1/3) core offload/reload (prior to 2000)	10	146	1,460
New fuel spent fuel pool loading	54	73	3,942
Full core offload/reload (2000-2063)	42	434	18,228
Cask storage loading campaigns	54	73	3,942

Sum of Load Cycles = 28,440

Conservatively doubling the sum of load cycles to account for miscellaneous fuel shuffles required to support refueling and cask loading operations:

Total Projected Load Cycles = 28,440 x 2 = 56,880 load cycles/80 years

Table 4.7.6-2
Evaluation Summary of Crane Operation

Crane	CMAA Service Class	Maximum Number of Load Cycles	Projected Number of Load Cycles for SPEO	Valid for SPEO
PSL Unit 2 Spent Fuel Handling Machine	Class A1	100,000	56,880	Yes

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The PSL Unit 1 and 2 crane load cycle limit TLAA has been demonstrated to remain valid through the SPEO in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

4.7.7 Flaw Tolerance Evaluation for CASS RCS Piping Components

TLAA Description

As part of the implementation of license renewal for PSL Units 1 and 2, FPL committed to manage the reduction in fracture toughness due to thermal aging of CASS RCS piping components through an aging management program (AMP) which would be consistent with the recommendations of NUREG-1801 (Reference ML103490041), AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)." The commitments for managing thermal aging of CASS components are documented as Item 8 in Appendix D, Table 1, of NUREG-1779 for PSL Unit 1 and Item 7 in Appendix D, Table 2, of NUREG-1779 for PSL Unit 2.

NUREG-1801, AMP XI.M12 requires that the effects of thermal embrittlement in susceptible materials be evaluated using the guidelines provided in the May 19, 2000 letter (Reference ML003717179) from Christopher Grimes, Nuclear Regulatory Commission (NRC), to Douglas J. Walters, Nuclear Energy Institute (NEI), to determine the material's susceptibility to thermal aging embrittlement based on casting method, molybdenum content and percent delta ferrite. NUREG-1801 also requires that the aging effects of potentially susceptible components must be managed through either enhanced volumetric examinations or through a plant or component specific flaw tolerance evaluation. FPL chose the flaw tolerance approach to demonstrate that the affected CASS piping components will remain structurally capable of performing their intended safety function during the 60-year license renewal period of extended operation (PEO). CASS RCS piping components that were determined to be susceptible to thermal aging embrittlement are listed in Tables 4.7.7-1 and 4.7.7-2 for PSL Units 1 and 2, respectively. The flaw tolerance evaluation for the PEO was performed by Structural Integrity Associates (SI) and consisted of a probabilistic fracture mechanics (PFM) evaluation to determine the tolerable flaw sizes, followed by the performance of a crack growth evaluation with a postulated flaw, to show that the tolerable flaws sizes would not be exceeded during the PEO. The PFM evaluation concluded that the susceptible RCS CASS piping components for PSL Units 1 and 2 are flaw tolerant. Prior to entering the PEO, NRC inspectors reviewed a sample of the flaw tolerance evaluation results for PSL Unit 1 (Reference ML16004A248) and PSL Unit 2 (Reference ML17334A308) and verified that the limiting CASS locations identified were evaluated for the PEO.

Although not required by NUREG-1801, AMP XI.M12, a one-time baseline ultrasonic (UT) examination of CASS RCS piping components adjacent to welds was performed prior to entering the PSL Units 1 and 2 PEO. This one time examination was considered a program enhancement to detect axial and circumferentially oriented service induced flaws that have at least 25% through wall depth. The PSL Unit 1 and Unit 2 baseline flaw examinations revealed no existing crack like indications with a 25% through wall depth.

Considering the current PSL Units 1 and 2 flaw tolerance evaluation for CASS RCS piping components includes a crack growth evaluation that is related to current 60-year PEO, the flaw tolerance evaluation is a TLAA for SLR.

TLAA Evaluation

For the 80-year subsequent period of extended operation (SPEO), SI prepared Report No. 2001262.402 (Reference 4.8.42), which documents the results of the flaw tolerance evaluation of CASS RCS piping components for PSL Units 1 and 2. The following technical aspects from the previous SI report for the 60-year PEO are addressed in SI Report No. 2001262.402 for the SPEO:

1. For the PEO, the saturated fracture toughness distributions used the correlations in NUREG/CR-4513, Revision 1 (Reference ML11356A348) for the CF8M CASS materials and are applicable for a delta ferrite level up to 25%. With the publication of NUREG/CR-4513, Revision 2 (Reference ML16145A082), which has saturated fracture toughness correlations up to 40% delta ferrite, the methodology used for the PEO for CASS RCS piping components with delta ferrite greater than 25% have been compared to those in NUREG/CR-4513, Revision 2 to demonstrate that they are still bounding.
2. An essential part of the flaw tolerance evaluation performed for the PEO is a crack growth evaluation which considered the growth of a hypothetical flaw for plant operation up to the end of the PEO, or approximately 20 years after the baseline UT examination. Since the SPEO period will be approximately 40 years after the baseline UT examination, the crack growth evaluation has been revisited for the SPEO using the most recent crack growth laws available in ASME Code Case N-809 (Reference 4.8.43) to determine the safe operating period.

As documented in SI Report No. 2001262.402, the fracture toughness for the PSL Units 1 and 2 CASS RCS piping components using the updated correlations in NUREG/CR-4513, Revision 2 for the SPEO are comparable to those derived for the PEO using the correlations in NUREG/CR-4513 Revision 1. Therefore, the crack growth resistance (J-R) curves used for the PEO remain applicable for the 80-year SPEO.

The J-R curves distributions are an important input in the PFM evaluation methodology used to determine the maximum tolerable flaw size. Since the J-R curves for the PEO remain applicable for SPEO, and since the other inputs used in the determination of the tolerable flaw size (stresses and geometry) remain unchanged, the maximum tolerable flaw sizes determined for the PEO also remain applicable for 80-year SPEO.

The flaw tolerance evaluation for the PEO also included a fatigue crack evaluation to ensure that crack growth with a postulated initial flaw size will not exceed the tolerable flaw size during the extended operating period. The SI report for the PEO used projected 60-year cycles for thermal transients to calculate the annual cycles for fatigue crack growth evaluation. The projected cycles for the 80-year SPEO thermal transients are provided in Section 4.3.1. Updated fatigue crack growth evaluations were performed using the 80-year projected cycles and applying the fatigue crack growth law of ASME Section XI Code Case N-809. This ASME Code Case contains the reference crack growth rate curves for CASS materials. The SPEO evaluations were performed assuming an initial postulated flaw of 25 percent of wall thickness with length 6 times the depth, consistent with the PEO evaluation.

The same stresses used in the PEO report were also utilized in SI Report No. 2001262.402 for the SPEO. For the SPEO, the SI Report used an updated version of crack growth software pc-Crack, which eliminated some of the unnecessary conservatisms in the PEO report.

The crack evaluation performed for the PSL Units 1 and 2 SPEO using an updated crack growth law for Type 316 stainless steel and 80-year projected cycles are presented in Table 4.7.7-3 and show that with an initial postulated quarter thickness flaw with length six times the depth, the tolerable flaw sizes are not reached until after 960 months (80 years) of operation for the susceptible PSL Units 1 and 2 CASS RCS piping components. These results confirm that the thermally aged PSL Units 1 and 2 CASS RCS piping components are demonstrated to be flaw tolerant. Furthermore, since acceptable baseline inspections of the PSL Units 1 and 2 CASS RCS piping components were performed prior to entering the PEO, no further inspections are required to manage thermal aging embrittlement of CASS RCS piping components during the 80-year SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The flaw tolerance evaluation performed in SI Report No. 2001262.402 concluded that the crack stability results, fracture toughness, and fatigue crack growth results for PSL Units 1 and 2 CASS RCS piping components are acceptable for 80 years of plant operation. Therefore, the flaw tolerance evaluation is projected through the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

Table 4.7.7-1
PSL-1 CASS RCS Piping Components Potentially Susceptible to Thermal Aging Embrittlement

Description	Piece Number
Pressurizer Surge Line Pipe	505-02-2
Pressurizer Surge Line Pipe	505-08-1
Pressurizer Surge Line Pipe	505-08-2
Pressurizer Surge Line Elbow	505-03-1
Pressurizer Surge Line Elbow	505-04
Safety Injection Nozzle Safe End (1A1 Cold Leg)	508-04-1
Safety Injection Nozzle Safe End (1B1 Cold Leg)	508-04-2
Safety Injection Nozzle Safe End (1B2 Cold Leg)	508-04-3
Safety Injection Nozzle Safe End (1A2 Cold Leg)	508-04-4

Table 4.7.7-2
PSL-2 CASS RCS Piping Components Potentially Susceptible to Thermal Aging Embrittlement

Description	Piece Number
Pressurizer Surge Line Pipe	751-102
Pressurizer Surge Line Pipe	751-110
Pressurizer Surge Line Elbow	751-104
Pressurizer Surge Line Elbow	751-107
Pressurizer Surge Line Elbow	751-109
RCP 2A2 Discharge Safe End	731-101
RCP 2B1 Discharge Safe End	731-101
RCP 2B2 Discharge Safe End	731-101
RCP 2A2 Suction Safe End	731-101
RCP 2B1 Suction Safe End	731-101

Table 4.7.7-3
80-Year Results of CASS Reevaluation for PSL Units 1 and 2

<table>
<tr><th rowspan="3">Unit</th><th rowspan="3">Component</th><th colspan="3">Tolerable Flaw Size for (θ/π = 0.15)</th><th colspan="2">Reevaluated 80-Year Crack Growth Results</th><th rowspan="2">Operating Period Evaluated</th></tr>
<tr><th rowspan="2">Servic e Level</th><th colspan="2">Tolerable Flaw Depth</th><th colspan="2">Final Flaw Depth</th></tr>
<tr><th>[a/t]</th><th>in</th><th>[a/t]</th><th>in</th><th>months</th></tr>
<tr><td rowspan="3">Unit 1
Unit 2</td><td rowspan="3">All Pressurizer Surge Line Components</td><td>A</td><td>0.75</td><td>0.98</td><td rowspan="3">0.3394</td><td rowspan="3">0.4452</td><td rowspan="3">960</td></tr>
<tr><td>B</td><td>0.75</td><td>0.98</td></tr>
<tr><td>C/D</td><td>0.75</td><td>0.98</td></tr>
<tr><td colspan="8"></td></tr>
<tr><td rowspan="3">Unit 1</td><td rowspan="3">Safety Injection Nozzle Safe-Ends</td><td>A</td><td>0.75</td><td>0.98</td><td rowspan="3">0.3293</td><td rowspan="3">0.4321</td><td>960</td></tr>
<tr><td>B</td><td>0.75</td><td>0.98</td><td>960</td></tr>
<tr><td>C/D</td><td>0.75</td><td>0.98</td><td>960</td></tr>
<tr><td colspan="8"></td></tr>
<tr><td rowspan="3">Unit 2</td><td rowspan="3">RCP Suction and Discharge Safe-Ends</td><td>A</td><td>0.75</td><td>2.40</td><td rowspan="3">0.2559</td><td rowspan="3">0.8190</td><td>960</td></tr>
<tr><td>B</td><td>0.75</td><td>2.40</td><td>960</td></tr>
<tr><td>C/D</td><td>0.75</td><td>2.40</td><td>960</td></tr>
</table>

4.7.8 Unit 2 Structural Weld Overlay PWSCC Crack Growth Analyses

TLAA Description

Structural weld overlays (SWOLs) were implemented on several PSL Unit 2 reactor coolant system (RCS) piping locations to eliminate concerns with primary water stress corrosion cracking (PWSCC) of Alloy 182 dissimilar metal welds. The susceptible locations that include SWOLs are as follows:

- Pressurizer surge nozzle
- Pressurizer relief valve nozzle
- Hot leg shutdown cooling nozzles
- Hot leg surge nozzle
- Hot leg drain nozzle

PWSCC analyses for the Alloy 182 dissimilar metal welds and butter, extending into the Alloy 52M SWOLs were performed by Framatome for the current 60-year PEO. The purpose of the analyses was to provide the acceptable period of operation (APO) between inspections for each SWOL location based on the crack growth analyses (CGA) performed in accordance with Non-Mandatory Appendix C of Section XI of the ASME Code (Reference 4.8.44) with the use of applicable operating transients and associated cycles.

Since PSL Unit 2 SWOL PWSCC crack growth analyses are based on time-dependent operating transients and associated cycles, they are considered a TLAA for PSL Unit 2 and require evaluation for the SPEO.

SWOLs were also implemented on several PSL Unit 1 RCS piping locations to eliminate concerns with PWSCC of Alloy 182 dissimilar metal welds. Similar analyses were performed by Structural Integrity (SI) for these SWOLs in accordance with Non-Mandatory Appendix C of Section XI of the ASME Code. SI screened the PSL Unit 1 crack growth analyses against the six TLAA criteria defined in 10 CFR 54.3(a). The screening determined that the analyses did not meet Criterion 3 because the analyses do not involve time-dependent assumptions defined by the current operating period. The assessment of design basis transient cycles was made on a time period less than that used for the current operating term. Therefore, the PSL Unit 1 SWOL crack growth analyses do not require evaluation as a TLAA for the SPEO.

TLAA Evaluation

For the 80-year SPEO, Framatome prepared non-proprietary Document No. 86-9329648-000 (Reference 4.8.45) and proprietary Document No. 86-9329645-000 (Reference 4.8.46) to establish the APO between inspections, based on the predicted crack growth acceptance criteria within the Non-Mandatory Appendix C of Section XI of the ASME Code period. The most limiting acceptable period of operation between inspections for the SPEO is 18.1 years, which corresponds to PSL Unit 2 hot leg surge nozzle.

For the current PEO, both the PSL Units 1 and 2 SWOLs are examined in accordance with ASME Code Case N-770-5 (Reference 4.8.47). Code Case

N-770-5 requires the SWOLs to be placed in a population to be examined on a sample basis. Twenty-five percent of the SWOL population is currently examined once in each 10-year inspection interval. This examination requirement remains applicable for the SPEO as the limiting APO of 18.1 years for the SPEO is greater than the required 10-year inspection interval.

Additional information regarding the methodology used by Framatome and the detailed results of the crack growth analyses are included in non-proprietary Framatome Document No. 86-9329648-000 and proprietary Document No. 86-9329645-000.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of cracking on the intended functions of the PSL Unit 2 RCS piping SWOLs will be managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

4.8 References

4.8.1 Westinghouse Report WCAP-18609-NP, Revision 2, St. Lucie Units 1 & 2 Subsequent License Renewal: Time-Limited Aging Analyses on Reactor Vessel Integrity, July 16, 2021. (Enclosure 4, Attachment 4).

4.8.2 10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events”.

4.8.3 U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, Regulatory Guide 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials,” May 1988.

4.8.4 Westinghouse Report WCAP-18102-NP, Revision 2, “Beaver Valley Unit 1 Heatup and Cooldown Limit Curves for Normal Operation,” March 2021.

4.8.5 Westinghouse Report LTR-SDA-II-20-32-NP, Revision 3, St. Lucie Units 1 & 2 Subsequent License Renewal: 80-Year Projected Transient Cycles, July 15, 2021. (Enclosure 4, Attachment 5).

4.8.6 Westinghouse letter report LTR-SDA-20-104-NP, Revision 2, St. Lucie Units 1&2 Subsequent License Renewal: Evaluation of Time-Limited Aging Analysis of the Reactor Vessel Internals, July 9, 2021. (Enclosure 4, Attachment 12)

4.8.7 Westinghouse letter report LTR-SDA-20-104-P, Revision 2, St. Lucie Units 1&2 Subsequent License Renewal: Evaluation of Time-Limited Aging Analysis of the Reactor Vessel Internals, July 8, 2021 (Enclosure 5, Attachment 7)

4.8.8 EPRI Report TR-104534, Volume 1, 2 & 3, “Fatigue Management Handbook”, Research Project 3321, Revision 1, December 1994

4.8.9 Westinghouse Report LTR-SDA-II-20-31-NP, Rev. 2, St. Lucie Units 1 & 2 Subsequent License Renewal: Primary Equipment and Piping Environmentally Assisted Fatigue Evaluations, July 14, 2021 (Enclosure 4, Attachment 6).

4.8.10 Westinghouse Report LTR-SDA-II-20-31-P, Rev. 2, St. Lucie Units 1 & 2 Subsequent License Renewal: Primary Equipment and Piping Environmentally Assisted Fatigue Evaluations, July 14, 2021 (Enclosure 5, Attachment 2).

4.8.11 BWXT Report MSLEF-SR-01-NP, Revision 0, St. Lucie Unit 1 Replacement Steam Generator Environmentally Assisted Fatigue Report (Non-Proprietary), July 16, 2021 (Enclosure 4, Attachment 7).

4.8.12 BWXT Report MSLEF-SR-01-P, Revision 0, St. Lucie Unit 1 Replacement Steam Generator Environmentally Assisted Fatigue Report, July 16, 2021. (Enclosure 5, Attachment 3).

4.8.13 Framatome Document No. 86-9329647-000, St. Lucie SLR CUFen Evaluations Summary, – Non Proprietary, July 15, 2021. (Enclosure 4, Attachment 8).

4.8.14 Framatome Document No. 86-9329644-001, St. Lucie SLR CUFen Evaluations Summary, July 15, 2021 (Enclosure 5, Attachment 4).

4.8.15 Structural Integrity Report No. 2001262.403, Revision 0, Summary of Fatigue Usage for Charging Nozzle at St. Lucie, Units 1 and 2 for Subsequent License Renewal, June 25, 2021 (Enclosure 4, Attachment 9).

4.8.16 DOR Guidelines, "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors," U. S. Nuclear Regulatory Commission, June 1979.

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

4.8.18 Regulatory Guide 1.89, Revision 1, "Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants," U. S. Nuclear Regulatory Commission, June 1984.

4.8.19 EPRI NP-1558, "A Review of Equipment Aging Theory and Technology," Electric Power Research Institute, September 1980.

4.8.20 ASME Boiler and Pressure Vessel Code Section III, Rules for Construction of Nuclear Vessels, 1968 Edition.

4.8.21 ASME Boiler and Pressure Vessel Code Section III, Rules for Construction of Nuclear Power Plant Components, 1971 Edition.

4.8.22 CEN-367-A, Revision 0, "Leak-Before-Break Evaluation of Primary Coolant Loop Piping in Combustion Engineering Designed Nuclear Steam Supply Systems," February 1991

4.8.23 Westinghouse Report WCAP-18617-NP, Revision 1, St. Lucie Units 1 & 2 Subsequent License Renewal: Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis, June 3, 2021. (Enclosure 4, Attachment 10).

4.8.24 Westinghouse Report WCAP-18617-P, Revision 1, St. Lucie Units 1 & 2 Subsequent License Renewal: Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis, June 3, 2021. (Enclosure 5, Attachment 5).

4.8.25 NUREG/CR-4513, Revision 2 (May 2016) and Revision 1 (May 1994), "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems," O. K. Chopra, U.S. Nuclear Regulatory Commission, Washington, DC

4.8.26 CE Owners Group Topical Report, CE NPSD-1198-P, Revision 00, "Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs CEOG," February 8, 2001

4.8.27 Westinghouse Report LTR-SDA-20-097-NP, Revision 2, St. Lucie Units 1 & 2 Subsequent License Renewal: Alloy 600 Half Nozzle Repair Flaw Evaluation, May 5, 2021. (Enclosure 4, Attachment 11).

4.8.28 Westinghouse Report LTR-SDA-20-097-P, Revision 2, St. Lucie Units 1 & 2 Subsequent License Renewal: Alloy 600 Half Nozzle Repair Flaw Evaluation, May 5, 2021. (Enclosure 5, Attachment 6).

4.8.29 Westinghouse Calculation Note, CN-CI-02-71, Revision 2, "Summary of Fatigue Crack Growth Evaluation Associated with Small Diameter Nozzles in CEOG Plants," December 9, 2005.

4.8.30 Areva Report 51-9096519-000, Visual Inspection Data Sheet No. PSL 1-22-09

4.8.31 Westinghouse letter report LTR-SDA-20-104-NP, Rev. 2, St. Lucie Units 1&2 Subsequent License Renewal: Evaluation of Time-Limited Aging Analysis of the Reactor Vessel Internals, July 9, 2021 (Enclosure 4, Attachment 12)

4.8.32 Westinghouse letter report LTR-SDA-20-104-P, Rev. 2, St. Lucie Units 1&2 Subsequent License Renewal: Evaluation of Time-Limited Aging Analysis of the Reactor Vessel Internals, July 8, 2021 (Enclosure 5, Attachment 7).

4.8.33 ASME CE Owners Group Report, CEN-412, Revision 2, "Relaxation of Reactor Coolant Pump Casing Inspection Requirements," April 1993. CEOG Task 678.

4.8.34 O. K. Chopra, "Estimation of Fracture Toughness of Cast Stainless Steels during Thermal Aging in LWR Systems," NUREG/CR-4513, ANL-90/42, June 1991.

4.8.35 O. K. Chopra, "Estimation of Fracture Toughness of Cast Stainless Steels during Thermal Aging in LWR Systems," NUREG/CR-4513, ANL-93/22, Revision 1 August 1994.

4.8.36 O. K. Chopra, "Estimation of Fracture Toughness of Cast Stainless Steels during Thermal Aging in LWR Systems," NUREG/CR-4513, ANL-15/08, Revision 2, May 2016.

4.8.37 "Evaluation of Flaws in Austenitic Steel Piping," ASME, Journal of Pressure Vessel Technology, Vol. 108, Aug. 1986, pp. 352-366.

4.8.38 Westinghouse Report LTR-SDA-20-099-NP, Revision 1, St. Lucie Units 1&2 Subsequent License Renewal: Task 9E RCP Casing Code Case N-481 Evaluation, April 7, 2021. (Enclosure 4, Attachment 13).

4.8.39 Westinghouse Report LTR-SDA-20-099-P, Revision 1, St. Lucie Units 1&2 Subsequent License Renewal: Task 9E RCP Casing Code Case N-481 Evaluation, April 7, 2021. (Enclosure 5, Attachment 8).

4.8.40 CMAA Specification No 70 (CMAA-70), Specification of Electric Overhead Traveling Cranes, Crane Manufacturers Association of America, Inc., 1975.

4.8.41 Electric Overhead Crane Institute (EOCI) Specification 61 for Electric Overhead Traveling Cranes, 1961.

4.8.42 Structural Integrity Report No. 2001262.402, Revision 1, Flaw Tolerance Evaluation of St. Lucie Units 1 and 2 CASS Components for SLR, July 15, 2021. (Enclosure 4, Attachment 14).

4.8.43 ASME Section XI Code Case N-809, "Reference Fatigue Crack Growth Rate Curves for Austenitic Stainless Steels in Pressurized Water Reactor Environments Section XI, Division 1," dated June 23, 2015.

4.8.44 ASME Boiler and Pressure Vessel Code Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, 2007 Edition with 2008 Addenda.

4.8.45 Framatome Document No. 86-9329648-000, St. Lucie SLR Crack Growth Analysis Summary - Non-Proprietary, July 2, 2021. (Enclosure 4, Attachment 15).

4.8.46 Framatome Document No. 86-9329645-000, St. Lucie SLR Crack Growth Analysis Summary, July 1, 2021 (Enclosure 5, Attachment 9).

4.8.47 ASME Code Case N-770-5, “ASME/BPVC CASE N-770-2, “Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated With UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities Section XI, Division 1,” dated November 7, 2016.

APPENDIX A1

UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

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19.0 Aging Management Programs and Time-Limited Aging Analysis Activities

19.1 Introduction

The application for a renewed operating license for Unit 1 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 PSL Subsequent License Renewal Application (SLRA) and includes the following sections:

- Section 19.1.1 contains a listing of the PSL 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 is also one site-specific AMP for PSL, the Pressurizer Surge Line AMP (Section 19.2.2.44).
- Section 19.1.2 contains a listing of the time-limited aging analyses (TLAAs).
- Section 19.1.3 contains a discussion stating the relationship between the Florida Power & Light Company (FPL) Quality Assurance (QA) Program at PSL and the AMPs' corrective actions, confirmation process, and administrative controls elements.
- Section 19.1.4 contains a summary of the PSL Operating Experience (OE) Program.
- Section 19.2 contains a summary of the PSL programs used for managing the effects of aging. These AMPs are associated with either NUREG-2191 Chapter X or Chapter XI.
- Section 19.3 contains a summary of the TLAAs applicable to the SPEO.
- Section 19.4 contains the PSL 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.

19.1.1 Aging Management Programs

AMPs for PSL SLR are listed in Table 19-1 and described in Section 19.2. The AMPs are listed chronologically as they appear in NUREG-2191, with the Chapter X AMPs first, followed by the Chapter XI AMPs, and ending with the site-specific Pressurizer Surge Line AMP. The PSL AMPs are categorized as either existing AMPs or new AMPs for SLR. The existing PSL AMPs are renamed and enhanced as necessary to more closely align with AMPs described in NUREG-2191.

Table 19-1 reflects the status of the PSL AMPs at the time of the SLRA submittal. Regulatory commitments, which include AMP enhancements and implementation schedules for PSL AMPs are identified in the PSL SLR Commitment List within Section 19.4.

Table 19-1
List of PSL Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
X.M1	Fatigue Monitoring (Section 19.2.1.1)	Existing
X.M2	Neutron Fluence Monitoring (Section 19.2.1.2)	Existing
X.S1	Concrete Containment Unbonded Tendon Prestress (PSL U1 containment does not have prestressed tendons.)	N/A
X.E1	Environmental Qualification of Electric Equipment (Section 19.2.1.9)	Existing
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section 19.2.2.1)	Existing
XI.M2	Water Chemistry (Section 19.2.2.2)	Existing
XI.M3	Reactor Head Closure Stud Bolting (Section 19.2.2.3)	Existing
XI.M4	BWR Vessel ID Attachment Welds (PSL U1 is a PWR.)	N/A
XI.M5	(Deleted from NUREG-2191.)	N/A
XI.M6	(Deleted from NUREG-2191.)	N/A
XI.M7	BWR Stress Corrosion Cracking (PSL U1 is a PWR.)	N/A
XI.M8	BWR Penetrations (PSL U1 is a PWR.)	N/A
XI.M9	BWR Vessel Internals (PSL U1 is a PWR.)	N/A
XI.M10	Boric Acid Corrosion (Section 19.2.2.4)	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 19.2.2.5)	Existing
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (Section 19.2.2.6)	Existing
XI.M16A	Reactor Vessel Internals (Section 19.2.2.7)	Existing
XI.M17	Flow-Accelerated Corrosion (Section 19.2.2.8)	Existing
XI.M18	Bolting Integrity (Section 19.2.2.9)	Existing
XI.M19	Steam Generators (Section 19.2.2.10)	Existing
XI.M20	Open-Cycle Cooling Water System (Section 19.2.2.11)	Existing
XI.M21A	Closed Treated Water Systems (Section 19.2.2.12)	Existing
XI.M22	Boraflex Monitoring (PSL U1 does not credit Boraflex as a neutron absorber in spent fuel pit criticality analyses.)	N/A
XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section 19.2.2.13)	Existing
XI.M24	Compressed Air Monitoring (Section 19.2.2.14)	Existing

Table 19-1 (continued)
List of PSL Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
XI.M25	BWR Reactor Water Cleanup System (PSL U1 is a PWR.)	N/A
XI.M26	Fire Protection (Section 19.2.2.15)	Existing
XI.M27	Fire Water System (Section 19.2.2.16)	Existing
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks (Section 19.2.2.17)	Existing
XI.M30	Fuel Oil Chemistry (Section 19.2.2.18)	Existing
XI.M31	Reactor Vessel Material Surveillance (Section 19.2.2.19)	Existing
XI.M32	One-Time Inspection (Section 19.2.2.20)	New
XI.M33	Selective Leaching (Section 19.2.2.21)	New
XI.M35	ASME Code Class 1 Small-Bore Piping (Section 19.2.2.22)	Existing
XI.M36	External Surfaces Monitoring of Mechanical Components (Section 19.2.2.23)	Existing
XI.M37	Flux Thimble Tube Inspection (PSL U1 does not use bottom mounted moveable flux thimble tubes.)	N/A
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section 19.2.2.24)	New
XI.M39	Lubricating Oil Analysis (Section 19.2.2.25)	Existing
XI.M40	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (Section 19.2.2.26)	Existing
XI.M41	Buried and Underground Piping and Tanks (Section 19.2.2.27)	New
XI.M42	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section 19.2.2.28)	New
XI.S1	ASME Section XI, Subsection IWE (Section 19.2.2.29)	Existing
XI.S2	ASME Section XI, Subsection IWL (PSL U1 containment does not have prestressed tendons.)	N/A
XI.S3	ASME Section XI, Subsection IWF (Section 19.2.2.30)	Existing
XI.S4	10 CFR Part 50, Appendix J (Section 19.2.2.31)	Existing
XI.S5	Masonry Walls (Section 19.2.2.32)	Existing
XI.S6	Structures Monitoring (Section 19.2.2.33)	Existing
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section 19.2.2.34)	Existing
XI.S8	Protective Coating Monitoring and Maintenance (Section 19.2.2.35)	Existing
XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 19.2.2.36)	Existing

Table 19-1 (continued)
List of PSL 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 19.2.2.37)	New
XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 19.2.2.38)	New
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 19.2.2.39)	New
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 19.2.2.40)	New
XI.E4	Metal Enclosed Bus (Section 19.2.2.41)	New
XI.E5	Fuse Holders (PSL U1 does 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 19.2.2.42)	New
XI.E7	High-Voltage Insulators (Section 19.2.2.43)	New
N/A – PSL Site-Specific Program	Pressurizer Surge Line (Section 19.2.2.44)	Existing

19.1.2 Time-Limited Aging Analyses

The TLAA summaries applicable to PSL during the SPEO are identified in Table 19-2 and described in the sections subordinate to Section 19.3:

Table 19-2
List of Time-Limited Aging Analyses

Category (Section)	Time-Limited Aging Analyses Name	Section
Reactor Vessel Neutron Embrittlement (19.3.2)	Neutron Fluence Projections	19.3.2.1
	Pressurized Thermal Shock	19.3.2.2
	Upper-Shelf Energy	19.3.2.3
	Adjusted Reference Temperature	19.3.2.4
	Pressure-Temperature Limits and Low Temperature Overpressure Protection (LTOP) Setpoints	19.3.2.5
Metal Fatigue (19.3.3)	Metal Fatigue of ASME Class 1 Components	19.3.3.1
	Metal Fatigue of Non-Class 1 Components	19.3.3.2
	Environmentally-Assisted Fatigue	19.3.3.3
Environmental Qualification of Electric Equipment (19.3.4)	Environmental Qualification of Electric Equipment	19.3.4
Containment Liner Plate, Metal Containments, and Penetrations Fatigue (19.3.5)	Containment Liner Plate, Metal Containments, and Penetrations Fatigue	19.3.5
Other Site-Specific TLAAs (19.3.6)	Leak-Before-Break of Reactor Coolant System Loop Piping	19.3.6.1
	Alloy 600 Instrument Nozzle Repairs	19.3.6.2
	Unit 1 Core Support Barrel Repair Plug Preload Relaxation	19.3.6.3
	Reactor Coolant Pump Flywheel Fatigue Crack Growth	19.3.6.4
	Reactor Coolant Pump Code Case N-481	19.3.6.5
	Crane Load Cycle Limits	19.3.6.6
	Flaw Tolerance Evaluation for Reactor Coolant Loop cast austenitic stainless steel (CASS) Piping	19.3.6.7
	Cycle-dependent Fracture Mechanics of Flaw Evaluations	19.3.6.8

19.1.3 Quality Assurance Program and Administrative Controls

The FPL Quality Assurance (QA) Program for PSL implements the requirements of 10 CFR 50, Appendix B, 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 FPL 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 FPL QA Program are applicable to all AMPs and activities during the SPEO. The FPL QA Program procedures, review and approval processes, and administrative controls are implemented, as described in the FPL Topical QA Report, in accordance with the requirements of 10 CFR 50, Appendix B. The FPL QA Program applies to all structures and components (SCs) that have aging effects managed by a PSL AMP. Corrective actions and administrative (document) control for both safety-related and NNS SCs are accomplished in accordance with the established PSL 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.

19.1.4 Operating Experience Program

The PSL OE Program captures the OE from site-specific and industry sources and is systematically reviewed on an ongoing basis in accordance with the FPL 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 PSL 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 PSL OE Program.

19.2 Aging Management Programs

19.2.1 NUREG-2191 Chapter X Aging Management Programs

This section provides UFSAR summaries of the NUREG 2191 Chapter X AMPs associated with TLAAs.

19.2.1.1 Fatigue Monitoring

The PSL 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 TLAAs to provide reasonable assurance that they remain valid in accordance with 10 CFR 54.21(c)(1)(iii). This AMP 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 American Society of Mechanical Engineers (ASME) Section III, Class 1 cumulative usage factor (CUF) analyses, environmental-assisted fatigue analyses (CUF_{en} analyses), maximum allowable stress range reduction/expansion stress analyses for ANSI B31.7 and ANSI B31.1 components, ASME III fatigue waiver analyses, and cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses.

The AMP 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 AMP also sets applicable acceptance criteria (limits) on these parameters and verifies the continued acceptability of existing analyses through cycle counting and parameter monitoring.

This corrective actions specified by the program (e.g., reanalysis, component or structure inspections, or component or structure repair or replacement activities) are taken if the actual number of cycles approaches 80 percent of the analyzed values.

This AMP also relies on the PSL Water Chemistry AMP to provide monitoring of appropriate environmental parameters for calculating environmental fatigue multipliers (F_{en} values).

19.2.1.2 Neutron Fluence Monitoring

The PSL Neutron Fluence Monitoring AMP, previously the fluence and uncertainty calculation portion of the PSL Reactor Vessel Integrity Program, is an existing AMP. This AMP monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to reactor pressure vessel and reactor internal components to provide reasonable assurance 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 AMP is used to verify the continued acceptability of existing analyses through neutron fluence monitoring and 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, the calculational methods are performed in a manner that is consistent with Regulatory Guide (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 vessel or to reactor internal components.

This AMP'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) analyses that are required to be performed in accordance with the 10 CFR Part 50, Appendix G requirements and 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 PSL Reactor Vessel Material Surveillance AMP (Section 19.2.2.19) may provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this AMP. 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.

19.2.1.3 Environmental Qualification of Electric Equipment

The PSL Environmental Qualification of Electric Equipment AMP, previously the PSL Environmental Qualification 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 in-service (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 was 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. The aging evaluations for EQ equipment that specify a qualification of at least 80 years are TLAAs for SLR. The PSL EQ of Electrical Equipment AMP is implemented in accordance with 10 CFR 50.49 and 10 CFR 54.21(c)(1)(iii).

19.2.2 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.

19.2.2.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The PSL ASME Section XI Inservice Inspection, 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, loss of preload, reduction in fracture toughness, and loss of mechanical closure integrity. The AMP consists of periodic volumetric, surface, and/or visual examination of ASME 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 AMP 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 during the subsequent period of extended operation.

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.

19.2.2.2 Water Chemistry

The PSL Water Chemistry AMP, previously known as the Water Chemistry Control Program -Water Chemistry Subprogram, 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 PSL 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. PSL will continue to implement monitoring and control guidance updates from industry guidelines in accordance with NEI 03-08. The PSL Water Chemistry AMP is augmented by the PSL 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).

19.2.2.3 Reactor Head Closure Stud Bolting

The PSL Reactor Head Closure Stud Bolting AMP is an existing program related to and currently part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD AMP. The PSL Reactor Head Closure Stud Bolting 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.

19.2.2.4 Boric Acid Corrosion

The PSL 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% Zinc (Zn)), that may be adversely affected by some form of borated water leakage. The purpose of this AMP is to provide 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 PSL 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 PSL 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 Acid Inspection Program for Pressurized Water Reactors.”

19.2.2.5 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

The PSL 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 that manages the aging effect of primary water stress corrosion cracking (PWSCC) for pertinent nickel alloy materials (Alloy 600/82/182) in the reactor coolant system (RCS) pressure boundary. This AMP also addresses OE linked to PWSCC degradation of components or welds constructed from certain nickel alloys (e.g., Alloy 600/82/182) exposed to pressurized water reactor primary coolant at elevated temperatures. 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 PSL 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.

19.2.2.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

The PSL Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP is an existing AMP. This AMP augments the ASME Section XI inspections of reactor coolant system and connected components with service conditions above 482ºF, 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. PSL has chosen the component-specific flaw tolerance evaluation method for aging management of Class 1 CASS components.

The Class 1 CASS components for PSL include valve bodies, reactor coolant pump (RCP) casings and RCS piping.

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.

For the Class 1 RCS CASS piping and RCP pump casings, the component specific flaw tolerance evaluations have been updated for the 80-year SPEO as summarized in Section 19.3.6.7.

19.2.2.7 Reactor Vessel Internals

The PSL Reactor Vessel Internals AMP is an existing AMP. The AMP, in accordance with NEI 03-08 requirements, is based on the inspection and evaluation guidelines of EPRI Technical Report No. 3002017168 (MRP-227 Revision 1-A) with a gap analysis that identifies enhancements to the program that are needed to address increasing from a 60 to 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” provided the recommendations for this gap analysis. PSL will continue to implement inspection guidance updates from the industry Issues

Programs to manage the aging of the reactor vessel internals in accordance with NEI 03-08. This AMP will be enhanced to implement 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:

- Cracking, including SCC, IASCC, PWSCC, 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 (IE);
- Changes in dimensions due to void swelling (VS) or distortion; and
- Loss of preload due to thermal and irradiation-enhanced stress relaxation and creep.

19.2.2.8 Flow-Accelerated Corrosion

The PSL 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 which provides reasonable assurance that structural integrity will be maintained between inspections. Additionally, the software tool, FAC Manager, with the erosion module, is used to evaluate components for both FAC and erosion. An erosion basis document has also been developed for future erosion scopes.

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 PSL Flow-Accelerated Corrosion 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 condition. These limited situations are based on site OE and will be monitored similar to other FAC locations that are not modeled. Portions of this activity were previously part of the Pipe Wall Thinning Inspection Program.

19.2.2.9 Bolting Integrity

The PSL Bolting Integrity AMP, previously part of the Systems and Structures Monitoring Program and Periodic Surveillance and Preventative Maintenance Program, is an existing AMP that manages loss of preload, cracking, and loss of material for closure bolting for safety-related and NNS pressure-retaining and other mechanical 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 will rely 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 will 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 kilo-pounds per square inch); lubricant selection (e.g., not allowing the use of molybdenum disulfide); and proper torquing of bolts.

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, supplemented by volumetric where applicable, are effective in detecting the applicable aging effects, and the frequency of inspection is adequate 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 PSL corrective action program. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Non-ASME Code inspections include inspection parameters for items such as lighting and distance offset that provide an adequate examination.

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 the 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 bolts heads and threads per population at each Unit considering the environments of Units 1 and 2 are similar, then the integrity of the bolted joint will be evaluated on a case-by-case basis using methods, such as periodic pump vibration monitoring and trending, or operator walkdowns to confirm that sump pumps are appropriately maintaining sump levels.

For bolted joints that contain air or gas, the acceptability of the closure bolting will be evaluated on a case-by-case basis using one of the following methods:

- Inspections performed consistent with that of submerged closure bolting;
- Visual inspections for discoloration (applies when leakage of the environment inside the piping systems would discolor the external surfaces);
- Monitoring and trending of pressure decay when the bolted connection is located within an isolated boundary
- Soap bubble testing; or
- Thermography testing (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 are managed by checking the torque to the extent that the closure bolting is not loose.

High-strength closure bolting [actual measured yield strength greater than or equal to 150 kilo-pounds per square inch (ksi) (1,034 MPa)] may be subject to SCC. For all 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) and closure bolting for which yield strength is unknown, volumetric examination in accordance to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, is performed (e.g., acceptance standards, extend and frequency of examination). Specified bolting material properties (e.g., design and procurement specifications, fabrication and vendor drawings, material test reports) may be used to determine if the bolting exceeds the threshold to be classified as high-strength.

Indications of aging in ASME pressure retaining bolting are evaluated in accordance with Section XI of the ASME Code. Non-ASME Code inspections will follow acceptance criteria established in plant procedures and specifications. Leaking joints do not meet acceptance criteria.

19.2.2.10 Steam Generators

The PSL Steam Generators AMP, previously the PSL Steam Generator Integrity Program (SGIP), 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 AMP is modeled after NEI 97-06, "Steam Generator Program Guidelines" and the referenced EPRI Guidelines of NEI 97-06.

The establishment of a steam generator program for ensuring steam generator tube integrity is required by the PSL 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.

Volumetric inspections are performed on steam generator tubes to identify degradation such as PWSCC, outer diameter stress corrosion cracking (ODSCC), and loss of material (mechanical wear) 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.

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.

19.2.2.11 Open-Cycle Cooling Water System

The PSL Open-Cycle Cooling Water System AMP is an existing AMP, previously part of the Intake Cooling Water System Inspection Program and the Periodic Surveillance and Preventive Maintenance (PSPM) Program, that manages aging effects caused by exposure of internal surfaces of piping, piping components, valves, piping elements, and CCW heat exchangers to a raw water environment from the intake cooling water (ICW) system. The PSL 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 surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling, as well as routine inspection and maintenance, so that corrosion, erosion, protective coating failure, fouling, and biofouling cannot degrade the performance of systems serviced by the ICW system. A one-time CCW heat exchanger performance test was performed to confirm that the CCW heat exchanger tube cleaning frequency was sufficient to maintain the fouling (and resulting heat transfer capability) assumed in the design calculations. When ICW system temperature or pressure differential readings exceed a specified level, then on-demand ICW system testing is performed to verify operability of the system. Inspection methods primarily include visual inspection and eddy current testing (ECT), but also include ultrasonic testing (UT) as needed. This AMP also includes enhancements to the guidance in NRC GL 89-13 that address OE such that aging effects are adequately managed.

19.2.2.12 Closed Treated Water Systems

The PSL Closed Treated Water Systems AMP, previously known as the Chemistry Control Program – Closed-Cycle Cooling Water System Subprogram, 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 PSL Closed Treated Water Systems AMP uses EPRI TR-3002000590, Revision 2, “Closed Cooling Water Chemistry Guideline” per NUREG-2191, XI.M21A as modified by SLR-ISG-2021-02-Mechanical, Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance. PSL will continue to implement monitoring and control guidance updates from industry guidelines in accordance with NEI 03-08.

19.2.2.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is an existing AMP that is currently implemented as part of the PSL Structures Monitoring Program. The PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP was evaluated as a portion of the PSL Structures Monitoring AMP in the initial license renewal application. The PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is evaluated separately in the subsequent license renewal application 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 B30.2-2005, “Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist).”

19.2.2.14 Compressed Air Monitoring

The PSL 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 PSL Compressed Air Monitoring AMP:

- Instrument Air sub-system of the Compressed Air System
- Diesel Air Start sub-system of the Emergency Diesel Generator System

The PSL Compressed Air Monitoring AMP also manages components which supply instrument air to the containment isolation system, ventilation system, feedwater system, chemical and volume control system, and main steam system. No portion of the miscellaneous bulk gas systems is required to be included in the scope of the PSL Compressed Air Monitoring AMP.

The PSL Compressed Air Monitoring AMP manages the aging effect of loss of material due to corrosion in compressed air system components located downstream of system air dryers. Aging effects associated with components located upstream of the air dryers, or those exposed to an air environment that is not subject to the preventive or periodic actions of the PSL Compressed Air Monitoring AMP, will be managed by the PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.

The PSL Compressed Air Monitoring AMP includes monitoring of water (moisture), and other contaminants (particulate size and hydrocarbon content) as a preventive measure to keep compressed air quality within specified limits.

The PSL Compressed Air Monitoring AMP is based on the relevant aspects of the PSL response to NRC GL 88-14 and INPO SOER 88-01. The PSL Compressed Air Monitoring AMP incorporates the guidance from the most current ANSI/ISA standards, and will incorporate the guidance from ASME OM-2012, Division 2, Part 28, and EPRI TR-10847 for testing and monitoring of 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.

19.2.2.15 Fire Protection

The PSL Fire Protection AMP is an existing AMP, formerly a portion of the PSL 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). The PSL 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, as well as periodic visual inspection and functional tests of fire-rated doors so that their operability is maintained. The PSL Fire Protection AMP also requires periodic visual inspection of other passive fire protection features credited for the Fire Protection Program like oil collection dikes. The PSL Fire Protection AMP includes periodic inspection and testing of the halon fire suppression systems. UFSAR Section 9.5.1 provides for additional information on the PSL Fire Protection Program.

With respect to preventive actions, PSL 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, delamination, separation, 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, cracking, or elastomer degradation as applicable on fire damper assemblies;

d) No visual indications of missing parts, holes, and wear; and

e) No conditions 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 are performed to demonstrate that they are functional, and the surface condition of components is inspected for corrosion, nozzle obstructions, and other damage at a frequency in accordance with the plant's NRC-approved fire protection program.

Visual inspection of at least 10 percent of each type of sealed penetration is performed at a frequency in accordance with the plant's NRC-approved fire protection program or at least once every refueling outage. Visual inspections of fire-rated structures (fire barrier walls, ceilings, and floors), combustible liquid spill retaining features (oil collection dikes), fire-rated assemblies, and fire damper assemblies are conducted at a frequency in accordance with the plant's NRC-approved fire protection program. Periodic visual inspections and functional tests are conducted on fire doors, and their closing mechanisms and latches are verified functional, at a frequency in accordance with the plant's NRC-approved fire protection program.

The results of inspections and functional testing of the in-scope fire protection equipment are collected and analyzed, and unacceptable results are documented in the corrective action program. When performance degrades to unacceptable levels, the PSL corrective action program is utilized to drive improvement. During the inspection of penetration seals, if any sign of abnormal degradation is detected within the sample, the inspection sample size is expanded, in accordance with the approved PSL fire protection program, to include an additional 10 percent of each type of sealed penetration.

19.2.2.16 Fire Water System

The PSL Fire Water System AMP is an existing AMP, formerly part of the PSL Fire Protection Program. This AMP manages aging effects associated with water-based fire protection system components. This AMP manages loss of material, wall thinning, cracking, and flow blockage due to fouling by performing periodic visual inspections, tests, and flushes in accordance with the 2011 Edition of NFPA 25.

Testing or replacement of fast-response and traditional sprinkler heads that have been in service for 20 or 50 years, respectively, is performed in accordance with NFPA 25. In addition to NFPA codes and standards, portions of the water-based fire protection system that are: (1) normally dry but periodically subjected to flow and (2) 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 functions. 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 organic or inorganic material sufficient enough 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.

19.2.2.17 Outdoor and Large Atmospheric Metallic Storage Tanks

The PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP is an existing AMP, previously part of the PSPM Program and Structures Monitoring 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 Unit 1 and Common Unit tanks included within the scope of this AMP are as follows:

- Unit 1 Refueling Water Tank (U1 RWT)
- Treated Water Storage Tank (TWST)
- Unit 1 Condensate Storage Tank (U1 CST)
- Diesel Oil Storage Tank 1A (DOST 1A)
- Diesel Oil Storage Tank 1B (DOST 1B)

This AMP includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice. Sealant or caulking is used for outdoor tanks at the tank bottom interface. This AMP manages loss of material and cracking by conducting one-time and periodic internal and external visual and surface examinations. Inspections of caulking or sealant are supplemented with physical manipulation. Surface exams are conducted to detect cracking for the aluminum U1 RWT. Thickness measurements of tank bottoms are conducted to detect degradation (e.g., loss of material on the inaccessible external surface). 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.

19.2.2.18 Fuel Oil Chemistry

The PSL Fuel Oil Chemistry AMP is an existing AMP, previously known as the Chemistry Control Program – Fuel Oil Chemistry Subprogram, 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 (b) measures to verify the effectiveness of the mitigative actions and confirm the insignificance of an aging effect. This AMP includes periodic draining of accumulated water through tank bottom drains; periodic draining, cleaning, and internal visual inspection of the DOSTs, and periodic draining, cleaning, and (to the extent practical) internal inspection of the day tanks. Volumetric examinations are used to assess identified degradation and to monitor for wall loss on internal surfaces of the day tank.

Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the PSL Technical Specifications. Guidelines of American Society of Testing Materials (ASTM) Standards including ASTM D975 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 PSL One-Time Inspection AMP.

19.2.2.19 Reactor Vessel Material Surveillance

The PSL Reactor Vessel Material Surveillance AMP is an existing AMP formerly a portion of the PSL Reactor Vessel Integrity Program. This AMP includes withdrawal and testing of the surveillance capsule located at 83°, identified in UFSAR Table 5.4-3. This capsule will receive between one to two times the peak reactor vessel neutron fluence of interest at the end of the SPEO used in the TLAAs for upper-shelf energy (USE), PTS, and pressure-temperature (P-T) limits. The surveillance program 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. 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 PSL Reactor Vessel Material Surveillance AMP is to monitor the changes in fracture toughness to the ferritic reactor vessel beltline and extended beltline materials. As

described in RIS 2014-11, beltline and extended 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.

This AMP 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.

The objective of the PSL 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 PSL Neutron Fluence Monitoring AMP.

This is a condition monitoring AMP 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 PSL Reactor Vessel Material Surveillance program is also used in conjunction with the PSL 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 E185-82, 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. With lead factors of less than 1, there is no need to remove a capsule for later reinsertion.

19.2.2.20 <u>One-Time Inspection</u>

The PSL One-Time Inspection AMP is a new condition monitoring 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 subsequent period of extended operation; (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 PSL 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 PSL One-Time Inspection AMP is used to verify the effectiveness of the PSL Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis AMPs. For carbon steel components exposed to water environments that do not include corrosion inhibitors as a preventive action (e.g., raw water and waste water) or carbon steel components that do not have wall thickness measurement examinations conducted of a representative sample of each environment between the 50^{th} and 60^{th} year of operation, 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), and structural integrity].

Periodic inspections are used instead of the PSL One-Time Inspection AMP 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.

19.2.2.21 Selective Leaching

The PSL 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% Zn or greater than 8% Al in susceptible environments. One-time inspections for components exposed to a closed-cycle cooling water or treated water environment will be conducted, based on PSL plant-specific OE which has not revealed selective leaching in these environments. Opportunistic and periodic inspections will be conducted for selective leaching susceptible components exposed to raw water, waste water, soil, and groundwater environments. Opportunistic inspections will be performed whenever components are opened, or whenever buried or submerged surfaces are exposed. The periodic inspections are conducted at an interval of no greater than every 10 years during the SPEO. 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 Unit 1 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 Unit 1. For each population with less than 35 susceptible components, one destructive examination will be performed in each 10-year inspection interval at Unit 1. Where the sample size is not based on the percentage of the population and the inspections will be conducted periodically (not one-time inspections), a reduction in the total number of inspections is acceptable as follows. Eight visual and mechanical inspections (reduced from 10 visual and mechanical inspections) and two destructive examinations will be conducted at Unit 1. If there are less than 35 susceptible components in a sample population at each unit, then one destructive examination will be performed for that sample population at Unit 1.

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.

19.2.2.22 ASME Code Class 1 Small-Bore Piping

The PSL 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 a nominal pipe size (NPS) diameter less than 4-inches and greater than or equal to 1-inch. This AMP provides a one-time volumetric and/or destructive examination of a sample of this Class 1 piping and includes full penetration (butt) and partial penetration (socket) welds. The PSL 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 are performed to determine whether cracking is occurring in the total population of ASME Code Class 1 small-bore piping in the plant. Per NUREG-2191, Table XI.M35-1, PSL Unit 1 is a Category A plant because it has no history of age-related cracking. 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 non-destructive 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 of this ASME Code Class 1 Small-Bore Piping 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 will be implemented.

19.2.2.23 External Surfaces Monitoring of Mechanical Components

The PSL External Surfaces Monitoring of Mechanical Components AMP is an existing AMP that was formerly the PSL Systems and Structures Monitoring Program.

The PSL External Surfaces Monitoring of Mechanical Components AMP is a condition monitoring AMP that manages loss of material, cracking, hardening or loss of strength (of elastomeric and polymeric components), reduction of heat transfer due to fouling (air to fluid heat exchangers), and blistering. The PSL 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 of metallic, polymeric, and elastomer components 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 susceptible stainless steel, copper alloy, and aluminum components. Periodic visual inspections or surface examinations are conducted to manage cracking in metallic components every 10 years during the SPEO. Component surfaces that are insulated and may be exposed to condensation and insulated outdoor components are inspected at least every 10 years or more frequently as required by plant specific OE. Surfaces that are not readily visible during plant operations and refueling outages are inspected opportunistically when made accessible or within an interval that would provide reasonable assurance the components' intended functions are maintained. Other inspections are performed at a frequency not to exceed one refueling cycle.

For certain materials, such as flexible polymers and elastomers, 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 PSL External Surfaces Monitoring of Mechanical Components AMP. 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.

19.2.2.24 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new AMP that manages loss of material, cracking, blistering, wall thinning, reduction of heat transfer due to fouling, flow blockage, and hardening or loss of strength of polymeric materials. Applicable environments will include air, diesel exhaust, raw water, treated water, waste water, fuel oil, and lubricating oil. Some inspections and activities within the scope of the new AMP were previously performed by the PSL 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 and loss of material of stainless steel, copper alloy (>15% Zn), and aluminum components. Aging effects associated with items (except for elastomers) within the scope of the PSL Open-Cycle Cooling Water AMP, the PSL Closed Treated Water Systems AMP, and the PSL Fire Water System AMP are not managed by this AMP.

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 25 components per unit will be inspected for applicable aging effects. Where the sample size will not be based on the percentage of the population, a reduction in the total number of inspections to 19 components inspected per unit is acceptable for the following material and environment combinations because site operating experience has not indicated a difference in aging effects between the two units for the environments listed:

- Air – indoor uncontrolled environment and aluminum, carbon steel, stainless steel, carbon steel with stainless steel internal cladding, cast iron, nickel alloy, and elastomer materials;
- Air – outdoor environment and aluminum, carbon steel, galvanized steel, and stainless steel materials;
- Raw water environment for systems supplied by the same raw water supply (i.e., ICW systems and fire protection systems) and carbon steel, copper alloy, galvanized steel, and stainless steel.

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 procedure will be used.

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.

19.2.2.25 Lubricating Oil Analysis

The PSL Lubricating Oil Analysis AMP is an existing program, previously performed as part of PSL'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 PSL Lubricating Oil Analysis AMP maintains lubricating 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.

There are no components utilizing hydraulic oil in the scope of the PSL Lubricating Oil Analysis AMP.

The effectiveness of the PSL Lubricating Oil Analysis AMP will be validated by the results of inspections completed under the PSL One-Time Inspection AMP.

19.2.2.26 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

The PSL Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP, formerly the PSL Metamic® Insert Surveillance Program, is an existing condition monitoring AMP that is implemented to provide reasonable assurance that degradation of the neutron-absorbing material used in spent fuel pools, that could compromise the criticality analysis, will be detected. This AMP relies on periodic inspection, testing, monitoring, and analysis of the criticality design to provide reasonable assurance that the required 5 percent subcriticality margin is maintained during the SPEO. This AMP consists of inspecting the physical condition of the neutron-absorbing material, such as visual appearance, dimensional measurements, weight, geometric changes (e.g., formation of blisters, pits, and bulges), and boron areal density as observed from coupons or in situ. This AMP addresses the aging management of the PSL spent fuel pools' credited neutron-absorbing materials, which include Metamic® inserts and Boral® panels.

19.2.2.27 Buried and Underground Piping and Tanks

The PSL Buried and Underground Piping and Tanks AMP is a new AMP. This a condition monitoring AMP that manages the aging effects associated with the external surfaces of buried and underground piping.

There are no buried or underground tanks at PSL.

This AMP manages the external surface condition of buried and underground piping for loss of material and cracking for the external surfaces of buried piping fabricated of steel (cast iron, carbon steel, ductile iron) and stainless steel through preventive measures (e.g., coatings, backfill, and compaction), mitigative measures (e.g., electrical isolation between piping and supports of dissimilar metals, etc.), and periodic inspection activities (e.g., direct visual inspection of external surfaces, protective coatings, wrappings and quality of backfill) during opportunistic or directed excavations. The number of inspections is based on the effectiveness of the preventive and mitigative actions.

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. Direct visual inspections are performed on the external surfaces, protective coatings, wrappings, quality of backfill and wall thickness measurements using NDE techniques. Additional inspections are performed on steel piping in lieu of fire main testing.

The table below provides additional information related to inspections. Preventive Action Category F has been selected for monitoring steel piping during the initial monitoring period since the proposed cathodic protection system will not be operational during that time period. Upon entering the SPEO, Preventive Action Category C has been selected for buried steel piping after the cathodic protection system has been in service for approximately 10 years and annual effectiveness reviews are performed. However, if these conditions were to change, the Preventive Action Category would require reevaluation and could potentially change.

The number of inspections for each 10-year inspection period, commencing 10 years prior to the start of SPEO, are based on the inspection quantities noted in NUREG-2191, Table XI.M41-2, adjusted for a 2-Unit plant site.

Material	No. of Inspections	Notes
Steel (buried)	11* prior to the SPEO (Category F) 4 in each 10-year period during the SPEO (Category C)	Includes 2 additional inspections to meet the requirements of NUREG-2191 Section XI.M41, paragraph 4.e.i regarding the aging effects associated with fire mains.
Steel (underground)	3	
Stainless steel (buried)	2	

*If after five years of operation the cathodic protection system does not meet the effectiveness acceptance criteria defined by NUREG-2191, Tables XI.M41-2 and -3 (-850 mV relative to a copper/copper sulfate reference electrode (CSE), instant off, for at least 80 percent of the time, and in operation for at least 85 percent of the time), FPL commits to performing two additional buried steel piping inspections beyond the number required by Preventive Action Category F resulting in a total of thirteen (13) inspections being completed six months prior to the SPEO.

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.

19.2.2.28 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP that will manage degradation of internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, fuel oil, and air 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. Portions of the program were previously part of the Intake Cooling Water System Inspection Program and the Periodic Surveillance and Preventive Maintenance (PSPM) Program. The PSL Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will not be used to manage loss of coating integrity for external coatings. The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will perform inspections of coatings/linings applied to components that will also be managed by the PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP, the PSL Open-Cycle Cooling Water AMP, PSL Closed Treated Water Systems AMP, PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP, PSL Fuel Oil Chemistry AMP, and the PSL Fire Water System AMP.

The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will manage 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 will be performed, where physically possible, in conjunction with the visual inspection.

For tanks and heat exchangers, all accessible surfaces will be inspected. Piping inspections will be sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings will be 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 will not be acceptable. Blisters will be evaluated by a coatings specialist to confirm the surrounding material is sound and the blister size and frequency is not increasing. Minor cracks in cementitious coatings will be acceptable provided there is no evidence of debonding. All other degraded conditions will be evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing will be performed where possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining. Additional inspections will be 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.

19.2.2.29 ASME Section XI, Subsection IWE

The PSL ASME Section XI, Subsection IWE AMP is an existing AMP that was previously part of the ASME Section XI, Subsection IWE Inservice Inspection Program. Inspections identify degradation of pressure-retaining components and their integral attachments to the Class MC steel containment. This condition monitoring AMP provides for inspection and examination of containment surfaces, pressure-retaining welds, seals, gaskets and moisture barriers, pressure-retaining bolting, and pressure-retaining components in accordance with the requirements of ASME Section XI, Subsection IWE, and consistent with 10 CFR 50.55a, “Codes and Standards,” with supplemental recommendations.

This AMP includes periodic visual, surface, and volumetric examinations, where applicable, for signs of degradation, damage, irregularities, and for coated areas distress of the underlying metal shell, and corrective actions. Acceptability of inaccessible areas of steel containment vessel is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas.

In addition, the AMP includes supplemental surface examination to detect cracking for non-piping penetrations (hatches, electrical penetrations, etc.) subject to cyclic loading that have no CLB fatigue analysis. If triggered by plant-specific OE, the AMP includes a one-time supplemental volumetric examination by sampling randomly-selected as well as focused locations susceptible to loss of thickness due to corrosion of the containment vessel that is inaccessible from one side. Inspection results are compared with prior recorded results in acceptance of components for continued service.

19.2.2.30 ASME Section XI, Subsection IWF

The PSL ASME Section XI, Subsection IWF AMP is an existing AMP that was previously known as the ASME Section XI, Subsection IWF Inservice Inspection Program. Inspections identify and correct degradation of ASME Class 1, 2, and 3 component supports. This condition monitoring AMP provides for inspection and examination of accessible surface areas of the component supports in accordance with the requirements of ASME Section XI, Subsection IWF.

This AMP consists of periodic visual examination of piping and component supports for signs of degradation, evaluation, and corrective actions. This AMP recommends additional inspections beyond the inspections required by ASME Code Section XI, Subsection IWF. This consists of a one-time inspection of an additional 5 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 subsequent period of extended operation. For high-strength bolting in sizes greater than 1-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.

19.2.2.31 10 CFR Part 50, Appendix J

The PSL 10 CFR Part 50, Appendix J AMP is an existing AMP that was previously part of the ASME Section XI, Subsection IWE Inservice Inspection AMP. The PSL 10 CFR Part 50, Appendix J AMP is a performance monitoring AMP that monitors leakage rates through the containment, including the containment vessel, 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 AMP is implemented in accordance with 10 CFR Part 50, Appendix J and NEI 94-01 Revision 2-A and is subject to the requirements of 10 CFR Part 54. 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 performance of the containment system.

19.2.2.32 Masonry Walls

The PSL Masonry Walls AMP is an existing AMP that previously was implemented as part of the PSL Structures Monitoring Program. The PSL Masonry Walls AMP is evaluated separately in the SLRA and 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 PSL Fire Protection AMP.

19.2.2.33 Structures Monitoring

The PSL Structures Monitoring AMP is an existing AMP that consists of periodic 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 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. Due to aggressive groundwater chemistry (Chlorides > 500 parts per million), the AMP will be enhanced prior to the SPEO to include site-specific evaluations, destructive testing, if warranted, and/or focused inspections of representative accessible (leading indicator) or below-grade inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed 5 years.

19.2.2.34 Inspection of Water-Control Structures Associated with Nuclear Power Plants

The PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is an existing AMP that is currently implemented as part of the PSL Structures Monitoring Program. The PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP was evaluated as a portion of the PSL Systems and Structures Monitoring AMP in the initial license renewal application. The PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is evaluated separately in the subsequent license renewal application and 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 PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP consists of inspection and surveillance of control structures for raw water. The structures within the scope of the PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP include the intake cooling water canal (the portion between the emergency cooling canal and the intake structure), emergency cooling canal, Unit 1 and Unit 2 intake structures, and ultimate heat sink dam. 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 PSL Structures Monitoring AMP.

19.2.2.35 Protective Coating Monitoring and Maintenance

The PSL Protective Coating Monitoring and Maintenance AMP is an existing AMP that was not previously credited for License Renewal. The PSL Protective Coating Monitoring and Maintenance AMP ensures monitoring and maintenance of Service Level I coatings is implemented in accordance with Position C4 of RG 1.54, Revision 3, for the subsequent period of extended operation. The AMP 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 D5163-08, "Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants." The AMP 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).

19.2.2.36 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PSL 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 insulation material within the scope of SLR subjected to adverse localized environments (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 plant-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 electrical cable and connection insulation. A sample population of electrical cable and connection insulation is utilized if testing is performed. If testing is deemed necessary, a sample of 20 percent of each electrical cable and connection insulation 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 being subjected to an adverse localized environment are evaluated for cumulative aging effects during the SPEO.

19.2.2.37 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits

The PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP is a new AMP. Portions of this AMP were previously part of the Containment Cable Inspection Program. This AMP manages the aging effects of the applicable cables and connections in the following systems/components:

- Nuclear Instrumentation: Excore Source, Intermediate, and Power Range Channels
- Control Room Air Intake Radiation Monitors

The purpose of this new 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 functions 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 to be completed no later than 6 months prior to the SPEO and at least once every 10 years thereafter.

19.2.2.38 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PSL Electrical Insulation for Inaccessible Medium-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 medium-voltage 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 is minimized due to effective automatic or passive drainage is not considered significant moisture for this AMP.

In-scope inaccessible medium-voltage power cables exposed to significant moisture will be 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-related degradation of the cable insulation. The first tests for subsequent 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 operating experience. The medium-voltage wetted cables at PSL are lead-sheathed, and therefore, will receive a one-time test prior to the SPEO. The results of this test will dictate any further actions.

This is a condition monitoring AMP. However, this AMP will include periodic actions to prevent inaccessible medium-voltage power cables from being exposed to significant moisture. Periodic actions to mitigate inaccessible medium-voltage power cable exposure to significant moisture will include inspection for water accumulation in cable manholes and conduits, and removing water, as needed. Inspections will be performed periodically based on water accumulation over time. The periodic inspection will occur 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 or flooding. The periodic inspection will include documentation of the effectiveness of either automatic or passive drainage systems, or manual pumping of manholes or vaults, in preventing inaccessible medium-voltage power cable exposure to significant moisture.

Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent removal of accumulated water by sump pumps prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or the control room. Reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

19.2.2.39 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PSL 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 that are within the scope of SLR and potentially 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 is a condition monitoring AMP. However, this AMP also 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, 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-related 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 in-service 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, in-service application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed in-service inaccessible I&C cables when testing is required in this AMP.

Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent removal of accumulated water by sump pumps prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or the control room. Reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

19.2.2.40 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PSL 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 current licensing basis 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) low-voltage power cables, including those designed for continuous wetting or submergence, within the scope of SLR potentially 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.

Periodic actions to mitigate inaccessible low-voltage power cable exposure to significant moisture include inspections 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 prior to the SPEO. Inspections are also performed after event-driven occurrences, such as heavy rain flooding. Inspection frequencies are adjusted based on inspection results including plant-specific OE.

Performing periodic visual inspections of low-voltage power cables accessible from manholes, vaults, or other underground raceways for jacket surface abnormalities. The visual inspections of low-voltage power cables occur at least once every 6 years and may be coordinated with the periodic inspections for water accumulation. Inaccessible and underground low-voltage power cables found to be exposed to significant moisture are evaluated to determine whether testing is required. Initial testing is performed once on a sample population to determine the condition of the electrical insulation. One or more tests may be required based on cable type, application, and electrical insulation material to determine the age-related degradation of the cable insulation. Inaccessible low-voltage power cables designed for continuous wetting or submergence are also included in this AMP. The need for additional periodic tests and inspections is determined by the test / inspection results as well as industry and plant-specific OE.

Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent removal of accumulated water by sump pumps prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or the control room. Reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

19.2.2.41 Metal Enclosed Bus

The PSL Metal Enclosed Bus AMP is a new AMP. Portions of this AMP were previously part of the Periodic Surveillance and Preventive Maintenance (PSPM) Program. 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 is a condition monitoring AMP. 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). The PSL Structures Monitoring AMP manages the aging effects on external metal enclosed bus (MEB) surfaces and structural supports. The first inspections 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 bar connections caused by repeated thermal cycling of connected loads by using low resistance testing using a micro-ohmmeter. A sample of 20 percent with a maximum sample of 25 constitutes a representative bolted bus connection sample size. In addition to 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 measuring connection resistance of bolted connections, for accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., PSL 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.

19.2.2.42 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PSL 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 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 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, will 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 AMP 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 AMP.

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.

19.2.2.43 High-Voltage Insulators

The PSL 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 PSL High-Voltage Insulators AMP was developed specifically to age manage high-voltage insulators (used on systems with nominal operating voltages greater than 1 kV and equal to or less than 765 kV) susceptible to aging degradation due to local environmental conditions. This AMP is applicable to different types of high-voltage insulators such as porcelain, toughened glass, and polymer.

This is a condition monitoring AMP that manages loss of material and 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.

This AMP 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 provides 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, polymer, 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, peeling of silicone rubber sleeves for polymer insulators, or degradation of glazing on porcelain insulators. Visual inspections may be supplemented with infrared thermography inspections to detect high-voltage insulator reduced insulation resistance. Corona cameras may also be employed to detect early signs of corona emissions.

The high-voltage insulators within the scope of this program are to be visually inspected at a frequency based on plant-specific OE with the specific type of insulator used (i.e., porcelain, polymer, toughened glass). The first inspections for SLR are to be completed prior to the SPEO.

19.2.2.44 Pressurizer Surge Line

The PSL Pressurizer Surge Line AMP, previously known as the Pressurizer Surge Line Inspection Program (Fatigue), is an existing AMP that was originally developed to address the effects of environmentally assisted fatigue (EAF) for the PSL pressurizer surge line welds during the initial period of extended operation (PEO).

The approach to address reactor water environmental effects of fatigue on the PSL Unit 1 pressurizer surge line accomplishes two objectives. First, the TLAA on fatigue has been resolved by confirming that the original transient design limits remain valid for the 80-year operating period. Confirmation by fatigue monitoring will ensure that these transient design limits are not exceeded. Second, reactor water environmental effects on fatigue life are examined using the most recent data from laboratory simulation of the reactor coolant environment. To address the initial 40-year operating period, Idaho National Engineering Laboratories evaluated fatigue-sensitive component locations in plants designed by all four U.S. nuclear steam supply system (NSSS) vendors, as reported in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," March 1995. This evaluation included calculation of fatigue usage factors for critical fatigue sensitive component locations of older vintage Combustion Engineering PWRs which match PSL relatively closely with respect to design codes used, as well as the analytical approach and techniques used. In addition, the design cycles considered in the evaluation match or bound the PSL Unit 1 design. Fatigue monitoring is performed to provide reasonable assurance that these limits are not exceeded. In this manner, the original transient design limits for fatigue are confirmed to remain valid for the current 40-year operating period, the initial 20-year PEO, and the 20-year SPEO of PSL Unit 1.

The PSL Unit 1 pressurizer surge line EAF analysis has been revised for the 80-year SPEO using the methodology outlined in NUREG/CR-6909, Revision 1, “Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, Final Report” for stainless steels, carbon and low-alloys steels, and Ni-Cr-Fe alloys. The results of the analysis confirms that the Pressurizer Surge Line AMP is appropriate for managing aging of the PSL Unit 1 pressurizer surge line during the SPEO.

The PSL Unit 1 surge line welds have previously been examined ultrasonically during the first three in-service inspection intervals in accordance with the requirements of ASME Section XI, Subsection IWB. All in scope PSL Unit 1 pressurizer surge line welds were examined in the PSL Unit 1 Inservice Inspection (ISI) 4th Interval except for one weld which is scheduled for examination during the refueling outage in the fall of 2025. The results of these inspections are utilized to assess fatigue of the surge lines. In addition to these inspections, EAF of the surge lines welds is addressed using the following approach:

(1) FPL elected to manage the effects of EAF of the pressurizer surge line welds by an aging management inspection program approved by the NRC.

(2) The aging management of the surge line is accomplished by a combination of flaw tolerance analysis as per ASME Boiler & Pressure Vessel Code, Section XI (applicable Edition and Addenda as referenced in the Unit 1 ISI Program Plan), Appendix L and inspection under the PSL ASME Section XI

Inservice Inspection, Subsections IWB, IWC, and IWD AMP. The aging effect managed with these inspections is cracking due to EAF. The technical justification and inspection frequency are supported by the flaw tolerance analysis based on the methodology noted in ASME Section XI, Nonmandatory Appendix L, "Operating Plant Fatigue Assessment." Based on postulated flaw tolerance analysis, and using the guidelines of ASME Code Section XI, Appendix L, Table L-3420-1, the periodic inspection schedule is determined to be 10 years.

(3) All in scope pressurizer surge line welds are examined in accordance with ASME Section XI, IWB for Class 1 welds, as modified by the requirements of 10 CFR 50.55a. Inservice examinations for the surge line welds include volumetric examinations. In each 10-year ISI interval during the SPEO, all in scope surge line welds are inspected in accordance with the PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP under Augmented programs within the ISI Program Plans. Note that welds with structural weld overlays (SWOL) have been screened out from the scope of analysis and inspections. The SWOL welds are inspected under PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP requirements.

19.3 Time-Limited Aging Analyses

With respect to plant TLAA, 10 CFR 54.21(c) requires 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 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 PSL Unit 1 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 TLAA, as defined in 10 CFR 54.3, are listed in Section 19.3.2 through, and including, Section 19.3.6.8 and are evaluated per the requirements of 10 CFR 54.21(c).

19.3.1 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 exemptions were based on TLAA. Based on this review, there is currently one active 10 CFR 50.12 exemption request for PSL Unit 1 that relates to a time sensitive TLAA topic. This TLAA-related exemption requests an exemption from the requirements of 10 CFR 50, Appendix G, to use the methodology of Topical Report CE NPSD-683-A, Rev. 06, "Development of a RCS Pressure and Temperature Limits Report for the Removal of P-T Limits and LTOP Requirements from the Technical Specifications," for the generation of the current P-T limits for the PSL Unit 1 reactor coolant pressure boundary during normal operating and hydrostatic or leak rate testing conditions. Specifically, use of the topical report methodology requires an exemption from the requirements of 10 CFR Part 50, Appendix G, Section IV.A.2, "Pressure-Temperature Limits and Minimum Temperature Requirements." This exemption was approved by the NRC in letter dated December 6, 2011 (Reference ML11297A096). The evaluation of this TLAA-related exemption for the 80-year SPEO is included in UFSAR Section 19.3.2.5.

19.3.2 Reactor Vessel Neutron Embrittlement

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, 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 PSL Reactor Vessel Material Surveillance AMP is described in Section 19.2.2.19.

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 TLAA concerns the effect of IE on the beltline and extended beltline regions of the PSL Unit 1 reactor vessel, 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 TLAA, as defined in 10 CFR 54.21(c). Therefore, the following TLAA were evaluated for the increased neutron fluence associated with 80 years of operations:

- Neutron fluence projections (Section 19.3.2.1)
- Pressurized thermal shock (PTS) (Section 19.3.2.2)
- Upper-shelf energy (USE) (Section 19.3.2.3)
- Adjusted reference temperature (Section 19.3.2.4)
- Pressure-temperature limits and low temperature overpressure protection (LTOP) setpoints (Section 19.3.2.5)

19.3.2.1 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. These fluence projections 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. The projected 80-year EFPY for PSL Unit 1 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 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 1.0×10^{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 PSL Neutron Fluence Monitoring AMP and the PSL Reactor Vessel Material Surveillance AMP ensure the continued validity and adequacy of projected neutron fluence analyses and related neutron fluence-based TLAAs as described in Section 19.2.1.2 and 19.2.2.19, respectively.

19.3.2.2 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, provides protection against PTS events. It establishes screening criteria on PWR vessel embrittlement, as measured by the maximum reference nil-ductility transition temperature in the limiting beltline component at the end of license, termed RT_{PTS}. RT_{PTS} screening values are set for beltline axial welds, forgings or plates, and for beltline circumferential weld seams for plant operation to the end-of-plant license. Calculating the reference temperature for pressurized thermal shock (RT_{PTS}) values is consistent with the methods given in Regulatory Guide 1.99.

The current PTS analysis, evaluated for 60 years of operation is a TLAA requiring evaluation for the 80-year SPEO since a change in the operating license term of the facility is being requested. The accepted methods of 10 CFR 50.61 were used with the maximum fluence values to calculate the RT_{PTS} values for the RPV materials at 72 EFPY. The limiting RT_{PTS} value for the PSL Unit 1 RPV base metal or longitudinal weld materials at 72 EFPY is 250.8°F, which corresponds to lower shell axial weld seams 3-203 A, B, & C (Heat # 305424). The limiting RT_{PTS} value for circumferentially-oriented weld materials at 72 EFPY is 135.3°F, which corresponds to the upper to intermediate shell girth weld seam 8-203 (Heat # 21935). All of the beltline reactor vessel materials have been projected to remain below the 10 CFR 50.61 RT_{PTS} screening criteria values of 270ºF for plates, forgings, and longitudinal welds, and 300ºF for circumferentially-oriented welds.

The PTS analyses have been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

19.3.2.3 Upper-Shelf Energy

Upper-shelf energy (USE) is the parameter used to indicate the toughness of a material at elevated temperature. There are two sets of rules that govern USE acceptance criteria. 10 CFR 50, Appendix G, Paragraph IV.A.1.a, states that RPV 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 ASME Code, Section XI.

The current licensing basis upper-shelf energy (USE) calculations were prepared for the Unit 1 RPV beltline and extended beltline materials for 52 EFPY. Since the USE value is a function of neutron fluence which is associated with a specified operating period, the USE calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for the 80-year SPEO.

There are two methods that can 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. For RPV beltline and extended beltline materials that are not in the surveillance program or have non-credible data, the Charpy USE (Position 1.2) is assumed to decrease as a function of fluence and copper content, as indicated in RG 1.99. When two or more credible surveillance sets become available from the RPV, they may be used to determine the Charpy USE of the surveillance material. The surveillance data are then used in conjunction with RG 1.99 to predict the change in USE (Position 2.2) of the RPV material due to irradiation. Per RG 1.99, when credible data exist, the Position 2.2 projected USE value should be used in preference to the Position 1.2 projected USE value.

The projected USE values were calculated to determine if the Unit 1 beltline and extended beltline materials remain above the 50 ft-lb criterion at 72 EFPY. The limiting PSL Unit 1 projected USE value for SPEO is intermediate shell plate C-7-3 with a projected USE of 54.8 ft-lb.

The USE analyses have been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

19.3.2.4 Adjusted Reference Temperature

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 adjusted reference temperature (ART) of the limiting beltline or extended beltline material is used to adjust the beltline pressure-temperature (P-T) limit curves to account for irradiation effects. Regulatory Guide (RG)1.99 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. 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. Since the ΔRT_{NDT} value is a function neutron fluence, these ART calculations meet the criteria of

10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for the 80-year SPEO.

The limiting 72 EFPY ART values for Unit 1 corresponds to the lower shell axial weld, seams 3-203 A, B, & C (Heat # 305424).

A determination of the applicability of the current end-of-license extension (EOLE) P-T limit curves can be made by comparing the ART values contained in the Unit 1 P-T limits analyses of record with the ART values determined for the SPEO. The results of the comparison conclude that the current PSL Unit 1 P-T limit curves and low temperature overpressure protection (LTOP) enable temperatures remain valid through the projected EOLE.

The PSL Unit 1 ART analyses have been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

19.3.2.5 Pressure-Temperature Limits and Low Temperature Overpressure Protection (LTOP) Setpoints

10 CFR Part 50 Appendix G requires that the reactor pressure vessel (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 PSL Unit 1 heatup and cooldown curves were calculated using the most limiting value of RT_{NDT} corresponding to the limiting material in the beltline and extended beltline regions of the reactor vessel for 54 EFPY. 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, the PSL Unit 1 Technical Specifications specify the power operated relief valve (PORV) lift settings required to mitigate the consequences of low temperature overpressure (LTOP) events. Each time the P-T limit curves are revised, the LTOP PORV lift settings must be reevaluated. Therefore, LTOP protection limits are considered part of the calculation of P-T curves.

The current 54 EFPY P-T limits for PSL Unit 1 requested an exemption from the requirements of 10 CFR 50, Appendix G, to use the methodology of Topical Report CE NPSD-683-A, Rev 06, for the generation of the P-T limits. In accordance with 10 CFR 50.12, the use of this exemption was approved by the NRC on December 6, 2011. The TLAA evaluation for the SPEO provides justification for continuation of this TLAA-related exemption through 54 EFPY for PSL Unit 1.

The PSL Unit 1 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 54 EFPY limit. The PSL Reactor Vessel Material Surveillance AMP (Section 19.2.2.19) will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval, as required, prior to exceeding the current terms of applicability for PSL Unit 1.

Therefore, the P-T limits and LTOP protection TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

19.3.3 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 TLAA for PSL. Specific components have been designed considering transient cycle assumptions, as listed in vendor specifications and the PSL Unit 1 UFSAR. Fatigue analyses are considered TLAA 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 19.3.3.1)
- Metal fatigue of Non-Class 1 components (Section 19.3.3.2)
- Environmentally-assisted fatigue (Section 19.3.3.3)

19.3.3.1 Metal Fatigue of Class 1 Components

The ASME Section III, Class 1 and ANSI B31.7, Class 1 Codes requires a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded. These 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 factors (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 Class 1 components were assessed for impact on fatigue:

- Reactor vessel
- Control element drive mechanisms
- RCS piping
- Steam generators
- Reactor coolant pumps
- Pressurizer
- Reactor vessel internals

With the exception of the loss of letdown flow transient, the 40-year design cycles (CLB cycles) for these Class 1 components were determined to bound 80 years of plant operations. For the SPEO, the loss of letdown flow transient was increased to 500 cycles. This transient is considered in the fatigue analyses of record (AORs) for the Class 1 cold leg charging nozzles, charging piping, and letdown piping. These analyses have been reconciled for the SPEO using 500 loss of letdown flow cycles. To accomplish this, the detailed fatigue results for the limiting component locations were extracted from the AORs and the component CUF was recalculated considering 500 loss of letdown flow cycles. The results demonstrate that the charging nozzles, charging piping, and letdown piping meet the CUF acceptance criterion assuming 500 loss of letdown flow cycles.

Therefore, the Class 1 component fatigue analyses remain valid for the SPEO. In order to provide reasonable assurance that the design cycles remain bounding in the fatigue analyses, the PSL Fatigue Monitoring AMP (Section 19.2.1.1) will track cycles for significant fatigue transients, including the loss of letdown flow transient, and provide reasonable assurance that corrective action is taken prior to potentially exceeding fatigue design limits. Therefore, the effects of fatigue on the intended function(s) of ASME Section III, Class 1 and ANSI B31.7, Class 1 components will be adequately managed by the PSL Fatigue Monitoring AMP (Section 19.2.1.1) for the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

19.3.3.2 Metal Fatigue of Non-Class 1 Components

The PSL Unit 1 non-Class 1 reactor coolant system (RCS) piping and balance-of-plant piping systems within the scope of subsequent license renewal are designed to the requirements of the ANSI B31.7 and ANSI B31.1 Codes. Piping and components designed in accordance with these Codes 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. These non-Class 1 piping Codes first require 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 B31.7 and 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 ANSI B31.7 and ANSI B31.1 piping systems 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 for all mechanical systems with the exception of the PSL Unit 1 RCS hot leg sample piping.

For the 60-year license renewal PEO, the RCS hot leg sample lines were determined to be limiting as these samples are taken on a daily basis. For the 80-year SPEO, daily hot leg samples would equate to 80 x 365 = 29,200 cycles and exceeds the 7000 thermal cycle limit assuming a stress range reduction factor (f) of 1.0. Therefore, a plant specific analysis was developed for the 80-year SPEO for PSL Unit 1 using a stress range reduction factor (f) of 0.7. Acceptable stress results were obtained with f = 0.7 and justifies a maximum number of cycles at 45,000 for the SPEO. This exceeds the 29,200 thermal cycles assumed for the 80-year SPEO for the PSL Unit 1 RCS hot leg sample line.

Therefore, the ANSI B31.7 and ANSI B31.1 allowable stress calculations remain valid for the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

19.3.3.3 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 cumulative usage factor (CUF_{en}) 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" 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. Any additional limiting locations are identified through an environmentally-assisted fatigue (EAF) screening evaluation. The EAF screening process evaluates existing CLB fatigue usage values for the ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 equipment and piping components, to determine the lead indicator (also referred to as sentinel) locations for EAF.

Calculations were prepared to document the evaluations of environmentally assisted fatigue for ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 pressure boundary components that are in contact with the reactor coolant and determine CUF_{en} values. The resultant CUF_{en} values for each of the ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 component locations are less than the ASME

Code limit of 1.0, with the exception of the pressurizer surge line, and are therefore acceptable. The Fatigue Monitoring AMP (Section 19.2.1.1) 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. In lieu of additional analyses to refine the CUF_{en} for the pressurizer surge line, PSL has selected aging management to address pressurizer surge line fatigue during the SPEO, consistent with what is currently done for the PEO.

Therefore, the effects of EAF on the intended functions of ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 component locations will be managed by the Fatigue Monitoring AMP (Section 19.2.1.1) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

For the pressurizer surge line, the effects of aging due to environmentally-assisted fatigue will continue to be managed by the Pressurizer Surge Line AMP (Section 19.2.2.44) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

19.3.4 Environmental Qualification of Electrical 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 TLAA. 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 Environmental Qualification 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 Environmental Qualification Program that specify a qualification of at least 60 years have been identified as TLAA for license renewal because the criteria contained in 10 CFR 54.3 are met.

The PSL Environmental Qualification of Electric Equipment AMP (Section 19.2.1.3) 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 lives.

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 Division of Operating Reactors (DOR) Guidelines, NUREG-0588, and NRC Regulatory Guide (RG) 1.89, Revision 1.

The PSL Environmental Qualification of Electric Equipment AMP (Section 19.2.1.3) will manage the effects of aging for the components associated with the EQ TLAA. This AMP 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 PSL Environmental Qualification of Electric Equipment AMP (Section 19.2.1.3) 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).

19.3.5 Containment Liner Plate, Metal Containments, and Penetrations Fatigue

Metal Containment Fatigue

The PSL Unit 1 containment vessel is fabricated from welded ASME-SA 516 Grade 70 steel plates to provide an essentially leak-tight barrier. Design criteria applied to the steel containment vessels assure that the specified leak rate is not exceeded under the design basis accident conditions. The PSL Unit 1 containment vessel is designed in accordance with the 1968 Edition of ASME Boiler and Pressure Vessel Code, Section III. The CLB for the PSL Unit 1 containment vessel includes a fatigue waiver evaluation that precludes the need for a detailed fatigue analysis.

A common evaluation of the PSL Units 1 and 2 containment vessel fatigue waivers was performed for SLR and concluded that the fatigue waivers remain valid through the 80-year SPEO since the service loading of the vessels met all the following six fatigue waiver conditions of the applicable ASME Codes:

1) Atmospheric to operating pressure cycles
2) Normal service pressure fluctuations
3) Temperature difference - startup and shutdown
4) Temperature difference - normal service
5) Temperature difference - dissimilar materials
6) Mechanical loads

Therefore, the fatigue waiver for the PSL Unit 1 containment vessel remains valid through the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

Penetrations Fatigue

The PSL Unit 1 containment penetrations are specified to withstand a lifetime total of 7000 cycles of expansion and compression due to maximum operating thermal expansion, and 200 cycles of other movements (seismic motion and differential settlement). The PSL Unit 1 containment penetrations are categorized as follows:

1) Type I - those which must accommodate considerable thermal movements (hot penetrations)
2) Type II - those which are not required to accommodate thermal movements (low temperature penetrations)
3) Type III - those which must accommodate moderate thermal movements (semi-hot penetrations)
4) Type IV - containment sump recirculation suction lines
5) Type V - fuel transfer tube

The thermal fatigue design limits of the Type I and Type III containment penetration bellows (7,000 thermal cycles) are bounded by the thermal fatigue design limits of their associated piping systems as discussed in UFSAR Sections 4.3.1 and 4.3.2. The 200 cycles of differential settlement and seismic motion are also bounding for the SPEO since they are not susceptible to any significant differential settlement they have not been subjected to any seismic loading to date.

Type II penetrations are low temperature penetrations, Type IV penetrations are only used during post-accident scenarios, and the Type V penetration is the PSL Unit 1 fuel transfer tube. As such, these penetrations are not exposed to large thermal loads or thermal movements; however, these penetrations were conservatively designed for 7,000 cycles of expansion and compression due to operating thermal expansion and 200 cycles of differential settlement and seismic motion. The 7000 thermal cycles and 200 cycles of differential settlement and seismic motion for Type II, Type IV, and Type V penetrations are bounding for the SPEO.

The analyses associated with the PSL Unit 1 containment penetration fatigue have been evaluated and determined to remain valid for the SPEO, in accordance with 10 CFR 54.21(c)(1)(i).

19.3.6 Other Plant-Specific TLAA

19.3.6.1 Leak-Before-Break of Reactor Coolant System Loop Piping

The Combustion Engineering Owners Group (CEOG) performed the leak-before-break (LBB) evaluation CEN-367-A for the PSL Units 1 and 2 primary loop piping in February 1991 along with other Combustion Engineering designed nuclear steam supply systems of similar layouts. The LBB evaluation was updated in 2009 for Unit 1 as part of the extended power uprate (EPU) project. In comparing the revised plant-specific loads for the EPU to the evaluation performed in CEN-367-A, the PSL Unit 1 RCS hot and cold leg piping remained qualified for the LBB under EPU conditions and that CEN-367-A remained applicable for PSL Unit 1.

WCAP-18617-P/NP performed the LBB evaluation for PSL Units 1 and 2 assuming an 80-year plant life. The analysis documented the plant-specific geometry, loading, and material properties used in the fracture mechanics evaluation.

The PSL Units 1 and 2 primary loop piping is constructed from carbon steel material with stainless steel cladding. The carbon steel cold leg piping is connected to the RCP suction and discharge nozzles and the nozzle safe-ends contain A351-CF8M CASS material and Alloy 600 dissimilar weld material. The CASS piping material is susceptible to thermal aging embrittlement at the reactor operating temperatures and the Alloy 600 weld material is susceptible to primary water stress corrosion cracking (PWSCC).

Based on NUREG/CR-4513, the fracture toughness correlations used for the full aged condition are applicable for plants operating at ≥ 15 EFPY for the A351-CF8M materials. For the 80-year SPEO, the materials will thermally age. Therefore, the use of the fracture toughness correlations is applicable for the fully aged or saturated condition of the PSL Units 1 and 2 RCP nozzle safe-ends. WCAP-18617-P/NP includes a recalculation of CASS fracture toughness properties based on NUREG/CR-4513 and the LBB analysis results for the CASS safe-end locations are acceptable for the thermal aging effect and for PWSCC. In addition, the fatigue crack growth analysis originally included in CEN-367-A used generic design basis transient cycles that envelope the projected 80-year transient cycles for PSL Units 1 and 2 to calculate the crack growth. Therefore, the generic fatigue crack growth analysis results are representative of the PSL Unit 1 and 2 fatigue crack growth and is applicable for the 80-year SPEO.

WCAP-18617-P/NP demonstrates that the conclusions reached in CEN-367-A remain applicable to PSL Unit 1 in accordance with 10 CFR 54.21(c)(1)(ii) and the dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis for the 80-year SPEO.

19.3.6.2 Alloy 600 Instrument Nozzle Repairs

Small bore Alloy 600 nozzles, such as pressurizer and RCS hot leg instrumentation nozzles in Combustion Engineering (CE) designed PWRs have developed leaks or partial through-wall cracks as a result of primary water stress corrosion cracking (PWSCC). The residual stresses imposed by the partial-penetration “J” welds between the nozzles and the low alloy or carbon steel pressure boundary components are the driving force for crack initiation and propagation.

PSL Unit 1 has experienced instances of Alloy 600 instrument nozzle leakage over the design life of the plant. Therefore, repairs have been done to Unit 1 RCS hot leg Alloy 600 instrument nozzles by relocating the partial penetration attachment weld from the interior surface of the component to the outside surface of the component. (Note that the PSL Unit 1 pressurizer has been replaced with a design that no longer utilizes Alloy 600 instrument nozzles). Preventative repairs were also performed on this population of instrument nozzles to prevent future leakage.

The Alloy 600 instrument nozzle repairs were previously evaluated for the 60-year PEO based on corrosion and fracture mechanics analyses justifying the acceptability of indications in the “J” weld based on a conservative corrosion rate, postulated flaw size, and flaw growth analyses. The repair evaluation was performed based on the fracture mechanics analysis provided in Combustion Engineering Owners Group (CEOG) Topical Report CE NPSD-1198-P and WCAP-15973-P-A and require evaluation for the SPEO.

Westinghouse letter report LTR-SDA-20-097-P/NP reassesses the Alloy 600 instrument nozzle repairs for the PSL Unit 1 SPEO and includes the following topics in accordance with the request in NRC Safety Evaluation (SE) related to WCAP-15973-P (Reference ML050180528):

a) Calculate the maximum bore diameter at the end of 80 years operation considering the carbon and low-alloy steel borated water corrosion to demonstrate that the limiting allowable bore diameters are not exceeded.

b) Reconcile that the fatigue crack growth and flaw stability evaluation in WCAP-15973-P remain valid for the 80 years operation of PSL Unit 1 to demonstrate that the ASME code acceptance criteria for crack growth and crack stability are met for the rest of the plant life including the extended operation.

c) Provide acceptable bases and arguments for concluding that unacceptable growth of the existing flaw by stress corrosion into the vessels or piping is improbable.

Westinghouse report LTR-SDA-20-097-P/NP addressed each of these topics as required by the NRC SE and determined that the conclusions reached in (CEOG) Topical Report CE NPSD-1198-P and WCAP-15973-P-A regarding the PSL Unit 1 Alloy 600 instrument nozzle repairs remain valid through the SPEO.

19.3.6.3 Unit 1 Core Support Barrel Repairs

During the 1983 PSL Unit 1 refueling outage, the RVI core support barrel (CSB) and thermal shield assembly were observed to be damaged. Four thermal shield support lugs were found to have become separated from the CSB and through-wall cracks were found in the CSB adjacent to the damaged lug areas. Corrective actions included permanent removal of the thermal shield and the CSB was repaired at the thermal shield support lug locations. Through-wall cracks were arrested with crack arrestor holes and non-through-wall cracks were machined out. The lug tear out areas were machined out and patched. The crack arrestor holes were sealed by inserting expandable plugs. Analysis of the CSB repairs was performed by the NSSS supplier to demonstrate that the repair patches and expandable plug design were acceptable for the remaining 40-year life of the plant consistent with ASME code allowable stresses.

For the original PSL license renewal, the PSL Unit 1 CSB analyses and follow-up inspections for the repaired CSB and the expandable plugs were screened against the six TLAA criteria and two specific elements of the repairs qualified as TLAAs; 1) fatigue analysis of the CSB middle cylinder; and 2) acceptance criteria for the CSB expandable plug preload based on irradiation induced stress relaxation. Note that fatigue of the CSB middle cylinder is addressed in Section 19.3.1.

For SLR, Westinghouse re-calculated the minimum plug-flange deflection requirements for the PSL Unit 1 CSB repair plugs using the increased 72 EFPY fluence. The Westinghouse calculation, LTR-SDA-20-104-P/NP, concludes that the CSB repair plug flange deflection measurement readings are sufficient to meet the minimum required values and maintain the plugs' preload. The CSB repair plugs will continue to perform their intended function for the SPEO.

The CSB repair plug irradiation induced stress relaxation calculation has been projected to the end of the SPEO, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

19.3.6.4 Reactor Coolant Pump Flywheel Fatigue Crack Growth

The reactor coolant pump (RCP) flywheels are discussed in Section 5.5.5 of the PSL Unit 1 UFSAR. During normal operation, the RCP 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.

The PSL Unit 1 RCP flywheel crack growth calculation was determined to be a TLAA for the original license renewal as discussed in Section 4.1.2 of NUREG-1779. In Section 5.5.5.3 of the PSL Unit 1 UFSAR, the RCP flywheel crack growth calculation indicates that the number of starting cycles required to cause a reasonably small crack to grow to critical size is more than 100,000. For the 60-year period of extended operation (PEO), the 100,000 RCP start cycles required to cause a crack to grow to critical size for PSL Unit 1 is far greater than the number of start cycles for this time period.

As discussed in Section 4.1.2 of NUREG-1779, the PSL Unit 2 RCP crack growth calculation was determined not to be a TLAA for the 60-year PEO as a review of the Unit 2 CLB did not identify or reference fatigue crack growth calculations for the flywheels. However, on October 9, 2019, FPL requested an amendment to the Renewed Facility Operating License for PSL Unit 2 to modify the Technical Specifications for the RCP flywheel inspection program requirements to be consistent with the conclusions and limitations specified in NRC safety evaluation (SE) of Topical Report SIR-94-080, Revision 1 “Relaxation of Reactor Coolant Pump Flywheel Inspection Requirements (Reference ML20013C086).

Topical Report SIR-94-080 conservatively assumes 4000 cycles of RCP startups and shutdowns in its analysis of fatigue crack growth rates. The evaluation of the RCP flywheel TLAA for PSL Unit 2 stated that the projected lifetime occurrences of plant heatups and cooldowns is 500 cycles based on the original plant 40-year design life and that the RCPs are cycled when filling and venting the RCS prior to unit start-up. Conservatively estimating three RCP start/stop cycles per fill and vent activity and a fill and vent activity for each heatup and cooldown results in (500 x 4) or 2000 RCP start/stop cycles the 80-year SPEO, which is well within the 4000 cycles assumed in Topical Report SIR-94-080. This conclusion is based on the fact that the 500 heatup and cooldown cycle limit for the 60-year PEO remain applicable for the PSL Unit 2 80-year SPEO as discussed in PSL Unit 2 UFSAR Section 19.3.3.1.

For the PSL Unit 1 SPEO, since to 4000 RCP stop/start cycle limit for PSL Unit 2 is more restrictive than the 100,000 stop/start cycle limit for PSL Unit 1, the 4000 RCP stop/start limit will be evaluated for PSL Unit 1. The assumed 2000 RCP start/stop cycles determined for the PSL Unit 2 60-year PEO above is also applicable to the PSL Unit 1 80-year SPEO and remains below the 4000 cycles of RCP startups and shutdowns assumed in Topical Report SIR-94-080

Therefore, the RCP flywheel fatigue crack growth analysis included in Topical Report SIR-94-080 has been demonstrated to remain valid for PSL Unit 1 through the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

19.3.6.5 Reactor Coolant Pump Code Case N-481

The PSL Unit 1 reactor coolant pumps (RCPs) are Byron-Jackson vertical, single bottom suction, horizontal discharge, centrifugal motor-driven pumps. The pump casings are fabricated from ASTM A-351, Grade CF-8M CASS material. In 1993, the Combustion Engineering Owners Group (CEOG) performed ASME Code Case N-481 flaw evaluations for several CE NSSS fleet pumps, including the PSL Units 1 and 2 RCPs. ASME Code Case N-481 allows visual inspections in lieu of volumetric inspections of the pump casing base metal and welds based on a fracture mechanics evaluation.

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, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS).” Specifically, GALL-SLR AMP XI.M12 provides an allowance for continued use of flaw tolerance evaluations performed as part of implementation of ASME Code Case N-481 to address thermal aging embrittlement. GALL-SLR AMP XI.M12 states that no further actions are needed if applicants demonstrate that (1) the original flaw tolerance evaluation performed as part of ASME Code Case N-481 implementation remains bounding and applicable for the subsequent license renewal (SLR) period or, (2) the evaluation is revised to be applicable for 80 years.

For SLR, Westinghouse performed a reconciliation analysis of the original Code Case N-481 evaluation. The current RCS piping loads and 80-year design transients and cycles were considered for the reconciliation. For the fatigue crack growth evaluation for SLR, a comparison to the more recently accepted fatigue crack growth rates were considered for stainless steel in an air environment from Appendix C of the ASME Section XI code.

Westinghouse reconciliation report LTR-SDA-20-099-P/NP was performed for the PSL RCP casings for the 80-year SPEO. The fatigue crack growth evaluations for the PSL Unit 1 RCP casings were reconciled for the 80-year SLR operation and the current ASME Section XI crack growth rate. The report updates the fracture toughness for the RCP casings in accordance with NUREG/CR-4513, Revisions 1 and 2, and since the stability against ductile tearing criterion is satisfied, only the crack growth mechanism is related to fatigue cycles. The report also evaluated the critical flaw sizes and acceptable period of operation based on non-ductile propagation, ductile tearing, and flow stress limit and concluded a postulated flaw will continue to grow until reaching the critical flaw size of 38 percent in about 130 years.

Therefore, the PSL Unit 1 RCP casings meet the material criteria in ASME Code Case N-481 for waiving volumetric examinations of cast austenitic pump casings, and inservice volumetric examinations of these RCP casings are not necessary for the 80-year SLR period of extended operation. However, visual (VT-3) examinations of casing inside surfaces, to the extent practical, are prudent whenever an RCP is disassembled for maintenance.

Therefore, the conclusions reached in the original CEOG RCP Code Case N-481 evaluation has been demonstrated to remain valid through the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

19.3.6.6 Crane Load Cycle Limits

A review of design specifications for cranes within the scope of SLR was performed to identify those cranes that comply with Crane Manufacturers Association of America Specification 70 (CMAA-70) 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.

The cranes considered to be a TLAA are those in compliance with NUREG-0612 and in the scope of SLR for their lifting function. The NUREG-0612 cranes are documented in PSL Unit 1 UFSAR Section 9.6.2. The following PSL Unit 1 cranes comply with NUREG-0612 and are included in scope of SLR for their lifting function:

- Reactor building polar crane
- Intake structure bridge crane
- Spent fuel cask handling crane
- Auxiliary telescoping jib crane
- Refueling machine 1-ton hoist
- Fuel pool bulkhead monorail
- Turbine building gantry crane

The PSL Unit 1 cranes are designed in accordance with Specification 61 of the Electrical Overhead Crane Institute (EOCI Specification 61). Although not originally designed to CMAA-70 requirements, Section 4.6.2 of NUREG-1779 indicates that the NRC staff concluded that the PSL Unit 1 cranes meet or exceed CMAA-70 criteria. The PSL Unit 1 spent fuel cask handling crane was replaced in 2003 and the replacement crane was designed in accordance with CMAA-70.

The PSL Unit 1 cranes are used primarily during refueling outages. Based on their historical and projected usage, the PSL Unit 1 spent fuel handling machine makes the most lifts at or near its rated capacity. Because the PSL Units 1 and Unit 2 spent fuel handling machines went into service in 1976 and 1983, respectively, and both units began doing full-core offloads after 2000, the PSL Unit 2 spent fuel handing machine is projected to be subjected to more full-core offloads than the PSL Unit 1 spent fuel handling machine during their respective 80-year plant lives.

CMAA-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 PSL Units 1 and 2 design specifications and CMAA-70, the applicable service class for the PSL Unit 1 cranes is Class A1. Table 3.3.3.1.3-1 of CMAA-70 states that a range of load cycles from 20,000 to 100,000 is applicable for cranes in Service Class A1 service thus establishing the envelope for the acceptable number of load cycles for this TLAA.

An evaluation has been performed for the PSL Unit 2 spent fuel handling machine and conservatively determined the crane would be subjected to 56,880 load cycles during the 80-year SPEO. This number of lift cycles is less than the 100,000 load cycle limit specified for Class A service.

Therefore, based on the bounding PSL Unit 2 spent fuel handling machine evaluation above, the PSL Unit 1 crane load cycle limits remain valid through the SPEO in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

19.3.6.7 Flaw Tolerance Evaluation for CASS RCS Piping

As part of the PSL Unit 1 original license renewal process, FPL committed to manage the reduction in fracture toughness due to thermal aging of CASS RCS piping components through an aging management program (AMP) which would be consistent with the recommendations of NUREG-1801, AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)." NUREG-1801, AMP XI.M12 requires that the effects of thermal embrittlement in susceptible materials be evaluated to determine the material's susceptibility to thermal aging embrittlement based on casting method, molybdenum content and percent delta ferrite. NUREG-1801 also requires that the aging effects of potentially susceptible components must be managed through either enhanced volumetric examinations or through a plant or component specific flaw tolerance evaluation. FPL chose the flaw tolerance approach to demonstrate that the affected CASS piping components will remain structurally capable of performing their intended safety function during the 60-year license renewal period of extended operation (PEO). The flaw tolerance evaluation for the PEO was performed by Structural Integrity Associates (SI) and consisted of a probabilistic fracture mechanics (PFM) evaluation to determine the tolerable flaw sizes, followed by the performance of a crack growth evaluation with a postulated flaw, to show that the tolerable flaws sizes would not be exceeded during the PEO. The PFM evaluation concluded that the susceptible RCS CASS piping components for PSL Unit 1 are flaw tolerant.

Although not required by NUREG-1801, AMP XI.M12, a one-time baseline ultrasonic (UT) examination of CASS RCS piping components adjacent to welds was performed prior to entering the PSL Unit 1 PEO. This one time examination was considered a program enhancement to detect axial and circumferentially oriented service induced flaws that have at least 25 percent through wall depth. The PSL Unit 1 baseline flaw examinations revealed no existing crack like indications with a 25 percent through wall depth.

For the 80-year subsequent period of extended operation (SPEO), SI prepared Report No. 2001262.402, which documents the results of the flaw tolerance evaluation of CASS RCS piping components for PSL Unit 1. As documented in SI Report No. 2001262.402, the fracture toughness for the PSL Unit 1 CASS RCS piping components using the updated correlations in NUREG/CR-4513, Revision 2 for the SPEO are comparable to those derived for the PEO using the correlations NUREG/CR-4513 Revision 1. Therefore, the crack growth resistance (J-R) curves used for the PEO remain applicable for the 80-year SPEO. Since the J-R curves for the PEO remain applicable for SPEO, and since the other inputs used in the determination of the tolerable flaw size (stresses and geometry) remain unchanged, the maximum tolerable flaw sizes determined for the PEO also remain applicable for 80-year SPEO.

The flaw tolerance evaluation for the PEO also included a fatigue crack evaluation to ensure that crack growth with a postulated initial flaw size will not exceed the tolerable flaw size during the extended operating period. Updated fatigue crack growth evaluations were performed using the 80-year projected cycles and applying the fatigue crack growth law of ASME Section XI Code Case N-809. For the SPEO, an updated version of crack growth software pc-Crack was used, which eliminated some of the unnecessary conservatisms in the PEO report.

The crack growth evaluation performed for the PSL Unit 1 SPEO using an updated crack growth law for Type 316 stainless steel and 80-year projected cycles show that with an initial postulated quarter thickness flaw with length six times the depth, the tolerable flaw sizes are not reached until after 960 months (80 years) of operation for the susceptible PSL Unit 1 CASS RCS piping components. These results confirm that the thermally aged PSL Unit 1 CASS RCS piping components are demonstrated to be flaw tolerant. Furthermore, since acceptable baseline inspections of the PSL Unit 1 CASS RCS piping components were performed prior to entering the PEO, no further inspections are required to manage thermal aging embrittlement of CASS RCS piping components during the 80-year SPEO.

Therefore, the flaw tolerance evaluation is projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

19.4 Subsequent License Renewal (SLR) Commitments List

Table 19-3
List of Unit 1 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
1	Fatigue Monitoring (19.2.1.1)	X.M1	Continue the existing PSL 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 monitor and track the loss of letdown flow transient during the SPEO. d) 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, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
2	Neutron Fluence Monitoring (19.2.1.2)	X.M2	Continue the existing PSL Neutron Fluence Monitoring AMP, including enhancement to: a) Follow the related industry efforts, such as by the Pressurized Water Reactor Owners Group (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-18124-NP-A or similar methodology for the determination of RPV fluence in regions above or below the active fuel region. b) Include justification that draws from Westinghouse's NRC approved RPV fluence calculation methodology and includes 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.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

Table 19-3
List of Unit 1 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
3	Environmental Qualification of Electric Equipment (19.2.1.3)	X.E1	Continue the existing PSL 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, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
4	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (19.2.2.1)	XI.M1	Continue the existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
5	Water Chemistry (19.2.2.2)	XI.M2	Continue the existing PSL Water 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.: PSL1: 09/01/2035
6	Reactor Head Closure Stud Bolting (19.2.2.3)	XI.M3	Continue the existing PSL Reactor Head Closure Stud Bolting AMP, including enhancement to: a) Procure reactor head closure stud materials to limit the maximum yield strength of replacement material to a measured yield strength less than 150 ksi and a maximum tensile strength of 170 ksi. b) Preclude the use of molybdenum disulfide (MoS_2) lubricant for the reactor head closure stud bolting.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

Table 19-3
List of Unit 1 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
7	Boric Acid Corrosion (19.2.2.4)	XI.M10	Continue the existing PSL BAC AMP, including enhancement to: a) Include other potential means to help in the identification of borated water leakage, such as the following, in order to identify potential borated water leaks inside containment that have not been detected during walkdowns and maintenance: • Airborne radioactivity monitoring • Humidity monitoring (for trending increases in humidity levels due to unidentified RCS leakage) • Temperature monitoring (for trending increases in room/area temperatures due to unidentified RCS leakage) • Containment air cooler thermal performance monitoring (for corroborating increases in containment atmosphere temperature or humidity with decreases in cooler efficiency due to boric acid plate out) b) Include a requirement in the PSL Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components AMP implementing documents to document evidence of boric acid residue (plating out of moist steam) inside containment cooler housings or similar locations such as cooling unit drain pans and to enter evidence in to the corrective action program to be evaluated under a boric acid corrosion control (BACC) program evaluation.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
8	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (19.2.2.5)	XI.M11B	Continue the existing PSL 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 alloy 600 material will be used in reactor coolant pressure boundary applications during the SPEO or that, if used,	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			appropriate baseline and subsequent inspections per MRP inspection guidance will be put in place.	
9	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (19.2.2.6)	XI.M12	Continue the existing PSL Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
10	Reactor Vessel Internals (19.2.2.7)	XI.M16A	Continue the existing PSL Reactor Vessel Internals AMP, including enhancement to: a) Implement the results of the gap analysis or implement the latest NRC-approved version of MRP-227 if it addresses 80 years of operation.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
11	Flow-Accelerated Corrosion (19.2.2.8)	XI.M17	Continue the existing PSL 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-R4) to ensure the exclusion remains valid and applicable for operation through 80 years. If actual wall thickness information is not available for use in this re-assessment, a representative sampling approach will be used. This re-assessment may result in additional inspections. b) Extend the erosion inspection plan for the duration of the SPEO. c) Perform opportunistic visual inspections of internal surfaces during routine maintenance activities to identify degradation. d) 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.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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			e) 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. f) Revise or provide procedure(s) to perform periodic wall thickness measurements of replacement components until the effectiveness of corrective actions have been confirmed. g) 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.	
12	Bolting Integrity (19.2.2.9)	XI.M18	Continue the existing PSL Bolting Integrity AMP, including enhancement to: a) Ensure references to EPRI Reports 1015336, 1015337, and NUREG-1339 are added and guidance incorporated, as appropriate, for selection of bolting material and the use of lubricants and sealants. b) Ensure lubricants containing molybdenum disulfide (MoS_2) or other lubricants containing sulfur will not be used for pressure-retaining bolting. c) Ensure that the maximum yield strength of replacement or newly procured pressure-retaining bolting material will be limited to an actual yield strength less than 150 ksi (1,034 MPa). In addition, 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 for pressure retaining bolting. For closure bolting greater than 2-inches in diameter (regardless of code	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			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) 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). The alternative testing will be completed on a case-by-case basis through: • Visual inspections of closure bolting during maintenance activities that make the bolt heads accessible and bolt threads visible; • Visual inspection for discoloration is conducted 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, or;	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• Thermography testing when the temperature of the fluid is higher than ambient conditions. e) 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. f) Ensure that closure bolting inspections will include consideration of the guidance applicable for pressure boundary bolting in NUREG-1339 and in EPRI NP-5769. g) 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 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. h) Evaluate leakage monitoring and sample expansion and add additional inspections if inspection results do not meet acceptance criteria as described in NUREG-2191, Chapter XI.M18, Element 7.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
13	Steam Generators (19.2.2.10)	XI.M19	Continue the existing PSL Steam Generators AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
14	Open-Cycle Cooling Water System (19.2.2.11)	XI.M20	Continue the existing PSL Open-Cycle Cooling Water System AMP, including enhancement to: a) Ensure program tests and inspections follow site procedures that include requirements for items such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes. b) Ensure the primary program document and applicable procedures and preventive maintenance activities include trending of wall thickness measurements at locations susceptible to ongoing degradation due to specific aging mechanisms (e.g., MIC). The PSL Open-Cycle Cooling Water System AMP will adjust the monitoring frequency based on the trending. c) Ensure the primary program document and applicable procedures and preventive maintenance activities clarify that when components do not meet or are projected to not meet the next inspection's minimum wall thickness requirements, the program includes reevaluation, repair, or replacement such components. d) Ensure that all above-ground, large-bore, safety-related ICW piping is replaced with AL6XN stainless steel piping. e) Clarify within the applicable procedures, specifications, and preventive maintenance activities that the 100% internal inspections of the ICW header piping will be supplemented with localized volumetric examinations (UT, radiography, etc.) as	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			applicable for areas where visual inspection alone is not adequate or as needed to determine the extent of degradation.	
15	Closed Treated Water Systems (19.2.2.12)	XI.M21A	Continue the existing PSL 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 on the internal surfaces exposed to the treated closed recirculating cooling water. 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 on the internal surfaces exposed to the treated closed recirculating cooling water. c) Ensure that visual inspections of closed treated water system components' internal surfaces are conducted whenever the system boundary is opened. When opportunistic visual inspections are conducted while the system boundary is open, they 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. d) 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:	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• 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 PSL is a two-Unit plant. e) 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. f) Ensure that the new inspection and test procedure(s) and/or preventive maintenance requirements report and evaluate any detectable loss of material, cracking, or fouling associated with the surfaces exposed to the treated closed recirculating cooling water per the PSL corrective action program. g) Ensure that the following additional inspections and actions are required if a post-repair/replacement inspection or subsequent inspection of surfaces exposed to the treated closed cooling water environment fails to meet acceptance criteria: • The number of increased inspections is determined in accordance with the PSL 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.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• 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 PSL 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.	
16	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (19.2.2.13)	XI.M23	Continue the existing PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, including enhancement to: a) Update the implementing procedure to state that, for the in-scope systems that are infrequently in service, such as the containment polar cranes, periodic inspections are performed once every refueling cycle just prior to use. b) Update the implementing procedure and inspection procedures to state their respective visual inspection frequencies required by ASME B30.2-2005. According to ASME B30.2-2005, inspections are performed within the following intervals: • "Periodic" visual inspections by a designated person are required and documented yearly for normal service applications • 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	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			requirements listed in ASME B30.2-2005 paragraph 2-2.1.3 (i.e., periodic inspection) c) Update the implementing procedure to ensure that the inspection procedures for the individual load handling systems are clearly identified and referenced. 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 ASME B30.2-2005. e) Update the governing procedure to state that repairs made to NUREG-0612 load handling systems are performed as specified in ASME B30.2-2005.	
17	Compressed Air Monitoring (19.2.2.14)	XI.M24	Continue the existing PSL 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: a) Incorporate the air quality provisions provided in the guidance of the EPRI TR-108147 and consider the related guidance in the ASME OM-2012, Division 2, Part 28. b) Perform opportunistic visual inspections of accessible internal surfaces for signs of corrosion and abnormal corrosion products that might indicate a loss of material within the system. c) Include inspections of internal air line surfaces downstream of the instrument air dryers and emergency diesel generator air start dryers with maintenance, corrective, or other activities that involve opening of the component or system.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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			d) Include inspection methods for the opportunistic inspections with guidance of standards or documents such as ASME OM-2012, Division 2, Part 28. e) Review air quality test results. f) Include requirements for better long-term trending of negative trends, more thorough documentation, and proactive aging management. g) Include monitoring and trending guidance from ASME OM-2012, Division 2, Part 28 as applicable.	
18	Fire Protection (19.2.2.15)	XI.M26	Continue the existing PSL Fire Protection AMP, including enhancement to: a) Enhance plant procedures to specify that penetration seals will be inspected for indications of increased hardness and loss of strength such as cracking, seal separation from walls and components, separation of layers of material, rupture, and puncture of seals. b) Enhance plant procedures to specify that subliming, cementitious, and silicate materials used in fireproofing and fire barriers will be inspected for loss of material, change in material properties, and cracking/delamination. c) Enhance plant procedures to specify that any loss of material (e.g., general, pitting, or crevice corrosion), cracking, or elastomer degradation (e.g., hardening, loss of strength, or shrinkage) as applicable to the fire damper assembly is unacceptable. d) Enhance plant procedures to require projection of identified degradation to the next scheduled inspection for all monitored fire protection SSCs, where practical.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			e) Enhance plant procedures to require that projections are 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.	
19	Fire Water System (19.2.2.16)	XI.M27	Continue the existing PSL Fire Water System AMP, including enhancement to: a) Update the governing AMP procedure to clearly state which procedures perform visual inspections for detecting loss of material, as well as state which procedures perform surface examinations or ASME Code, Section XI, VT-1 visual examinations for identifying SCC of copper alloy (>15% Zn) valve bodies, nozzles, and strainers. 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. The 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% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 19 components per population at each Unit is inspected. Where practical, the inspections will focus on the bounding or lead components most susceptible to aging. 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	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035 Implement the AMP and start inspections and tests no earlier than 5 years prior to the SPEO (03/01/2031). Perform the 10-year City Water Storage Tank bottom inspections within 10 years prior to the SPEO (03/01/2026).

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			water-based fire protection system components that are periodically subjected to flow but are normally dry. c) Update existing inspection/testing procedures and create new procedures to incorporate the surveillance requirements stated in NUREG-2191, Section XI.M27, Element 4 and Table XI.M27-1, which are based on NFPA 25, 2011 edition. This includes testing or replacement of fast-response and traditional sprinkler heads that have been in service for 20 or 50 years, respectively, in accordance with NFPA 25. d) Update the governing AMP procedure and trending procedure to state that where practical, degradation identified is projected 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. Results of flow testing (e.g., buried, and underground piping, fire mains, and sprinklers/spray nozzles), flushes, and wall thickness measurements are monitored and trended by either the Engineering or the 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 PSL 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.	

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			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 spray and sprinkler system flushing procedures to enable trending of data. Specifically, the existing flushing procedures (listed below) will be revised to document and trend deposits (scale or foreign material). Recommended methods for trending deposits may include the following as feasible: • Inspectors will take photographs of deposits. • Inspectors will measure the weight of the deposits. • Inspectors will measure elapsed time taken to complete a flush (i.e., the time required for the flushing water to turn an acceptable color). The documentation above will be maintained by the AMP owner for comparing and trending inspection/test results. Existing flushing procedures (listed below), as well as new flushing procedures, will include steps to compare the amount of deposits to the previous inspections' results, and if the trend is negative or if the projected solids for the next inspection/test/flush are anticipated to exceed an acceptable amount that would impact the system intended function, then the PSL corrective action program will be utilized to drive improvement. Additionally, identified deposits will be evaluated for potential impact on downstream components, such as sprinkler heads or spray nozzles.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			h) Update the governing AMP procedure to state that identified wall loss greater than the manufacturers tolerance will be entered into the corrective action program process for engineering evaluation. i) Update the governing AMP procedure to point to the inspection procedures which inspect the wall thicknesses and compare wall loss to the manufacturers tolerance. j) Update the governing AMP procedure to state that internal inspection, flow testing, and flushing procedures/ preventive maintenance activities must demonstrate that no loose fouling products exist in the systems that could cause flow blockage in the sprinklers or deluge nozzles. k) Update the governing AMP procedure and respective pipe inspection procedures to state that if an obstruction inside piping or sprinklers is detected during pipe inspections, the material is removed and the inspection results are entered into the PSL 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 Annex 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 PSL corrective action program. If a failure occurs (e.g., a through-wall leak or blockage impacting operability), the failure mechanism shall be identified and used to determine the most susceptible system locations for additional inspections, including consideration to the other Unit systems as driven by the corrective action program. When piping is replaced prior to failure, due to concerns with wall thinning or blockage, inspections are considered for similar areas of the system to determine the presence and extent of degradation. The	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			implementation of these augmented inspection actions provides reasonable assurance that the fire water system will continue to perform its function adequately through the SPEO. l) Update the existing flow test procedure and the existing deluge system flush/test procedure enhanced with new main drain tests 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 will be conducted. The number of increased tests is determined in accordance with the PSL 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 will be conducted to determine the further extent of tests. Since PSL is a two-Unit site, additional tests include inspections at both of the Units with the same material, environment, and aging effect combination. m) Update the primary program procedure and applicable preventive maintenance activities to state that, as a contingency, if degradation mechanisms such as MIC, erosion, or recurring loss of material due to internal corrosion were to occur, 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 PSL 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 PSL 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	

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			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.	
20	Outdoor and Large Atmospheric Metallic Storage Tanks (19.2.2.17)	XI.M29	Continue the existing PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP, including enhancement to: a) Create a new procedure, and/or associated preventive maintenance activities, to: • Address the interfaces, handoffs, and overlaps between the PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP and the following AMPs: ○ PSL Structures Monitoring AMP; ○ PSL External Surfaces Monitoring of Mechanical Components AMP; ○ PSL Water Chemistry AMP; ○ PSL Fuel Oil Chemistry AMP; ○ PSL One-Time Inspection AMP; ○ PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP; and	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035 Implement the AMP and start the 10-year interval inspections no earlier than 10 years prior to the SPEO (03/01/2026). Start the one-time inspections no earlier than 5 years prior to the SPEO (03/01/2031).

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			○ PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP. • Direct periodic (18-month interval) visual inspection of tank-to-concrete caulking/sealants, with mechanical manipulation as appropriate. Update or reactivate existing caulking/sealant inspection preventive maintenance activities and create new caulking/sealant inspection preventive maintenance activities as needed. These caulking/sealant inspections are performed by the PSL Structures Monitoring AMP. • Direct the 10-year bottom thickness measurement of the TWST, DOST 1A, DOST 1B, and the U1 CST, using low-frequency electromagnetic testing (LFET) techniques with follow-on UT examination, as necessary, at discrete tank locations identified by LFET. • Direct baseline one-time interior visual inspections of the U1 RWT. Direct 10-year surface examination inspections of the aluminum U1 RWT's interior nonwetted surface and exterior surface for evidence of loss of material and cracking. The surface examinations will inspect 25 1-square-foot sections or 25 1-linear-foot sections of welds. If evidence of cracking is identified, then a surface examination is also performed to determine the extent of the cracking. • Clarify that subsequent inspections are conducted in different locations unless this AMP includes a documented basis for conducting repeated volumetric and surface inspections in the same location.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• Clarify that inspections and tests are performed by personnel qualified in accordance with site procedures to perform the specified task. • Clarify that inspections and tests within the scope of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) follow procedures consistent with the ASME Code, including ASME Code Section XI. 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, or in the case of one-time inspections, identified degradation is projected to the end of the SPEO. • Clarify that results are evaluated against acceptance criteria to confirm or adjust timing of subsequent inspections, or in the case of one-time inspections, schedule follow-up inspections. • State the acceptance criteria as follows: ○ No degradation of paints or coatings (e.g., cracking, flakes, or peeling); ○ No non-pliable, cracked, or missing caulking/sealant for the tank bottom interface; ○ No indications of cracking of the aluminum walls and ceiling of the U1 RWT, and;	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			○ Measured or projected tank bottom thickness must be greater than 87.5% of the nominal plate thickness. (Not applicable to the U1 RWT) • 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 or repair/replace the degraded component as needed. ○ Repair or replace the degraded component as determined by engineering evaluation and perform follow-up examinations. For one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals. ○ Expand the inspection to include all tanks of with the same material-environment combination (for DOST degradation). ○ For other sampling-based inspections (e.g., 20%, 25 locations) the smaller of five additional inspections or 20% of the inspection population is conducted. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause is conducted to determine the further extent of inspection. The additional inspections include inspections at all of the Units with the same material, environment, and aging effect combination.	

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			Sample expansion inspections that happen in the next inspection interval are part of the preceding interval. b) Perform baseline one-time interior visual inspections of the U1 RWT. Perform 10-year surface examination inspections of the aluminum U1 RWT's interior nonwetted surface and exterior surface for evidence of loss of material and cracking. The surface examinations will inspect 25 1-square-foot sections or 25 1-linear-foot sections of welds. If evidence of cracking is identified, then a surface examination is also performed to determine the extent of the cracking. c) Perform 10-year LFET tank bottom thickness examinations of the TWST, DOST 1A, DOST 1B, and the U1 CST, with follow-on UT at discrete locations.	
21	Fuel Oil Chemistry (19.2.2.18)	XI.M30	Continue the existing PSL Fuel Oil Chemistry AMP, including enhancement to: a) Address the analysis of stored fuels in the day tanks describing analytical techniques and test frequencies for determining water and sediment content, total particulate concentration, and microbiological contamination levels. b) Address periodic tank cleaning, and visual or alternative internal inspections of the day tanks. c) Drain, clean, and visually inspect all DOSTs at least once during the 10-year period prior to the SPEO, and repeat the inspection at least once every 10 years. d) Require any pressure retaining boundary degradation identified during visual inspection be supplemented with volumetric (UT) wall thickness testing including bottom thickness measurements for the DOSTs if warranted.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035 Implement the AMP and start the one-time and 10-year interval inspections no earlier than 10 years prior to the SPEO (03/01/2026).

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			e) Prior to the SPEO, perform a one-time inspection of selected components exposed to diesel fuel oil in accordance with the PSL One-Time Inspection AMP to verify the effectiveness of the PSL Fuel Oil Chemistry AMP. f) Enhance monitoring and trending by: • Perform periodic fuel oil sampling of the day tanks. • Clarify that the sampling specifically monitors the following parameters for trending purposes: water content, sediment content, biological activity, and total particulate concentration for all DOSTs and day tanks. • Update frequency of ASTM D975 analysis to quarterly. g) Include the following monitoring and trending features in visual and volumetric inspection methodology: • Identified degradation is projected until the next scheduled inspection, where practical. • Evaluate the 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. h) Provide acceptance criteria, consistent with industry standards, for the testing requirement and approach used to detect the presence of water, particulates, and microbiological activity in stored diesel fuel within all DOSTs and day tanks.	

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			i) Include the following acceptance criteria features in visual and volumetric inspection methodology: • Report any degradation of the tank (including all DOSTs and day tanks) internal surfaces and evaluate using the corrective action program. • Evaluate thickness measurements of the DOST tank bottom against the design thickness and corrosion allowance. j) Provide corrective actions, such as addition of a biocide, to be taken should testing detect the presence of microbiological activity in stored diesel fuel. k) Address performing corrective actions to prevent recurrence when the specified limits for fuel oil standards are exceeded during periodic surveillance.	
22	Reactor Vessel Material Surveillance (19.2.2.19)	XI.M31	Continue the existing PSL Reactor Vessel Material Surveillance AMP, including an incremental adjustment to the approved capsule withdrawal schedule to withdraw and test the surveillance capsules located at 263° and 83° in accordance with the NRC approved withdrawal schedule.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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23	One Time inspection (19.2.2.20)	XI.M32	Implement the new PSL One-Time Inspection AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035 Implement the AMP and start the one-time inspections no earlier than 10 years prior to the SPEO (03/01/2026).
24	Selective Leaching (19.2.2.21)	XI.M33	Implement the new PSL 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.: PSL1: 09/01/2035 Implement the AMP and start the one-time and 10-year interval inspections no earlier than 10 years prior to the SPEO (03/01/2026).
25	ASME Code Class 1 Small-Bore Piping (19.2.2.22)	XI.M35	Continue the existing PSL ASME Code Class 1 Small-Bore Piping AMP, which includes: a) Perform one-time inspection of small-bore piping using the methods, frequencies, and acceptance criteria as outlined in NUREG-2191, Section XI.M35. 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, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035 Implement the AMP and start the inspections within 6 years prior to the SPEO (03/01/2030).

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
26	External Surfaces Monitoring of Mechanical Components (19.2.2.23)	XI.M36	Continue the existing PSL External Surfaces Monitoring of Mechanical Components AMP, including enhancement to: a) Indicate the material and environment combinations where external examinations could be credited to manage the aging effects of the internal surfaces of components as detailed in the PSL External Surfaces Monitoring of Mechanical Components AMP. b) Incorporate the aging management activities currently performed for external corrosion of insulated piping at PSL in the PSL External Surfaces Monitoring of Mechanical Components program procedure. c) Ensure all components made of stainless steel, aluminum, or copper alloys with greater than 15% Zn or 8% Al inspected by this program will have periodic visual or surface examinations conducted to manage cracking. d) Monitor the aging effects for elastomeric and flexible polymeric components through a combination of visual inspection and manual or physical manipulation of the material. Manual or physical manipulation of the material will include touching, pressing on, flexing, bending, or otherwise manually interacting with the material. The purpose of the manual manipulation will be 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. Flexing of polymeric components (e.g., expansion joints) 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) will be conducted to detect potential reduction in impact strength as indicated by a crackling sound or surface cracks when flexed. Examples of inspection parameters for elastomers and polymers will include:	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• 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. e) Specify that this program will also manage hardening or loss of strength, loss of preload for heating, ventilation, and air conditioning (HVAC) closure bolting, and blistering using visual inspections. In addition, physical manipulation will be used to manage hardening or loss of strength and reduction in impact strength. f) Specify that, when required by the ASME Code, inspections will be conducted in accordance with the applicable code requirements. And, when non-ASME Code inspections and tests are required, inspections will follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, and presence of protective coatings. Inspections, except those for cracking and under insulation, will be performed every refueling outage. g) Ensure that periodic visual inspections or surface examinations will be conducted on components made of stainless steel, aluminum, or copper alloys with greater than 15% Zn or 8% Al to manage cracking every 10 years during the SPEO and other	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			inspections will be performed at a frequency not to exceed one refueling cycle. 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 provide reasonable assurance that the components' intended functions are maintained. h) Specify that, when inspecting to manage cracking of a component's material, either surface examinations conducted in accordance with plant-specific procedures or ASME Code Section XI VT-1 inspections (including those inspections conducted on non-ASME Code components) are conducted on each component inspected. An inspection requires that at least 20% of the surface area of the component is inspected, unless the component is measured in linear feet, such as piping. Any combination of 1-ft length sections and components can be used to meet the recommended extent of 20% of the population of materials and environment combinations, with a maximum of 25 inspections required in each population. An inspection of a component in a more severe environment may be credited as an inspection for the specified environment and for the same material and aging effects in a less severe environment (e.g., an outdoor air environment is more severe than an indoor uncontrolled air environment which is more severe than an indoor controlled air environment, assuming that there are no borated water leaks in the indoor environments). i) Specify that, when inspecting insulated components in an outdoor environment or that may be exposed to condensation in an indoor environment, that the population and sample sizes used for inspections will be determined based on the material type (e.g., steel, stainless steel, copper alloy, aluminum) and environment (e.g., air outdoor, air accompanied by leakage) combination. A minimum of 20% of the in-scope piping length, or 20% of the surface area for components whose configuration does not	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			conform to a 1-ft axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Alternatively, any combination of a minimum of twenty-five 1-ft axial length sections and components for each material type is inspected, with a maximum of 25 inspections required in each population. j) Ensure that visual inspections 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. 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. 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. The sample size for manipulation will be at least 10% of available surface area. k) Indicate that the following alternatives to removing insulation after the initial inspection will be acceptable: i. Subsequent inspections may consist of examination of the exterior surface of the insulation with sufficient acuity to detect indications of damage to the jacketing or protective outer layer (if the protective outer layer is waterproof) of the insulation when the results of the initial inspections meet the following criteria:	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• No loss of material due to general, pitting, or crevice corrosion beyond that which could have been present during initial construction is observed during the first set of inspections, and • No evidence of SCC is observed during the first set of inspections. If: (a) the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or jacketing, (b) there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), or (c) the protective outer layer (where jacketing is not installed) is not waterproof, then periodic inspections under the insulation should continue as conducted for the initial inspection. ii. Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of corrosion under insulation is low for tightly adhering insulation. Tightly adhering insulation is considered to be a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope piping that has tightly adhering insulation is visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections are not credited towards the inspection quantities for other types of insulation. l) Specify that 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.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			m) Include evaluation and acceptance guidance from EPRI TR-1009743, “Aging Identification and Assessment Checklist,” for visual/tactile inspections where appropriate. n) Specify that inspections to detect cracking in aluminum, stainless steel, and applicable copper alloy components will have additional inspections conducted if one of the inspections does not meet the 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. The number of increased inspections will be determined in accordance with the site’s corrective action process; however, 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 is inspected, whichever is less. The additional inspections are completed within the interval in which the original inspection was conducted. If 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. Additional samples will be inspected for any recurring degradation to provide reasonable assurance that corrective actions appropriately address the associated causes. The additional inspections include populations with the same material, environment, and aging effect combinations at both Unit 1 and Unit 2. o) Require that any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, will have their inspection frequencies adjusted as determined by the corrective action program.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
27	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (19.2.2.24)	XI.M38	Implement the new PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
28	Lubricating Oil Analysis (19.2.2.25)	XI.M39	Continue the existing PSL Lubricating Oil Analysis AMP, including enhancement to: a) Perform sampling and testing of old oil following periodic oil changes or on a schedule consistent with equipment manufacturer's recommendations or industry standards [e.g., ASTM D6224-02]. Plant specific OE associated with oil systems may also be used to adjust the schedule for periodic sampling and testing, when justified by prior sampling results. b) Ensure guidance indicates that 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).	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
29	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (19.2.2.26)	XI.M40	Continue the existing PSL Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP, including enhancement to: a) Inspect and test Metamic® inserts on a frequency dependent on the condition of the neutron-absorbing material and determined and justified with PSL-specific OE. For each Metamic® insert selected for surveillance, the maximum interval between each inspection and between each coupon test is not to exceed 10 years, regardless of OE; b) Compare observations and measurements from the periodic inspections and coupon testing to baseline information or prior measurements and analyses for trending analysis, projecting future degradation, and projecting the future subcriticality margin	Complete the initial Boral® testing and inspections no later than 6 months prior to the SPEO, i.e.: PSL1: 09/01/2035

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			of the spent fuel pool (SFP). This trending will also consider differences in exposure conditions, venting, spent fuel rack differences, etc. for each Metamic® insert or coupon selected for surveillance. c) Initiate corrective actions (e.g., add neutron-absorbing capacity with an alternate material, or apply other available options) to maintain the subcriticality margin if the results from measurements and analysis indicate that the 5% subcriticality margin cannot be maintained because of current or projected degradation of the neutron-absorbing material. d) Manage aging effects associated with the Boral® panels in the SFP cask area by monitoring for loss of material and changes in dimension that could result in loss of neutron-absorbing capability of the Boral® panels. Monitor parameters associated with the physical condition of the Boral® panels and include in-situ gap formation, geometric changes as observed from coupons or in situ, and decreased boron-10 areal density, etc. The parameters monitored are directly related to determination of the loss of material or loss of neutron absorption capability of the Boral® panels. These parameters are monitored using coupon and/or direct in-situ testing of the Boral® panels to identify their associated loss of material and degradation of neutron-absorbing capacity. The frequency of the inspection and testing depends on the condition of the neutron-absorbing material and is determined with site-specific OE; however, the maximum interval between these inspections is not to exceed 10 years, regardless of OE. Compare the Boral® inspection and testing measurements to baseline values for trending analysis and projecting future panel degradation and SFP subcriticality margins. The degradation trending must be based on samples that adequately represent the entire Boral® panel population, and the trending must consider differences in sample exposure conditions, differences in spent fuel cask racks, and possibly	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			other considerations. The new Boral® panel surveillance acceptance criteria for the obtained inspection, testing, and analysis measurements must ensure that the 5% subcriticality margin for the SFP will be maintained, otherwise corrective actions need to be implemented.	
30	Buried and Underground Piping and Tanks (19.2.2.27)	XI.M41	Implement the new PSL Buried and Underground Piping and Tanks AMP. a) Install cathodic protection systems and perform effectiveness reviews in accordance with Table XI.M41-2 in NUREG-2191, Section XI.M41. b) If after five years of operation the cathodic protection system does not meet the effectiveness acceptance criteria defined by NUREG-2191, Tables XI.M41-2 and -3 (-850 mV relative to a CSE, instant off, for at least 80% of the time, and in operation for at least 85% of the time), FPL commits to performing two additional buried steel piping inspections beyond the number required by Preventive Action Category F resulting in a total of 13 inspections being completed 6 months prior to the SPEO.	Implement AMP and start inspections no earlier than 10 years prior to the SPEO (03/01/2026). Install cathodic protection systems no later than 10 years prior to the SPEO (03/01/2026). Complete pre-SPEO inspections no later than 6 months or the last RFO prior to SPEO i.e.: PSL1: 09/01/2035
31	Internal Coatings/Linings For In-scope Piping, Piping Components, Heat Exchangers, and Tanks (19.2.2.28)	XI.M42	Implement the new PSL 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.: PSL1: 09/01/2035 Implement the AMP and perform baseline inspections no earlier than 10 years prior to the SPEO (03/01/2026).

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32	ASME Section XI, Subsection IWE (19.2.2.29)	XI.S1	Continue the existing PSL 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" and EPRI TR-104213, "Bolted Joint Maintenance & Application Guide." b) Augment existing procedures to specify that for structural bolting consisting of ASTM A325, ASTM A490, and equivalent materials, 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 implement periodic supplemental surface or enhanced visual examinations at intervals no greater than 10 years to detect cracking due to cyclic loading of all non-piping penetrations (hatches, electrical penetrations, etc.) that are subject to cyclic loading but have no current licensing bases fatigue analysis and are not subject to local leak rate testing. d) Augment existing procedures to implement supplemental one-time surface or enhanced visual examinations, performed by qualified personnel using methods capable of detecting cracking, 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. These inspections are intended to confirm the absence of SCC aging effects. If SCC is	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035 Start the one-time inspections for cracking due to SCC no earlier than 5 years prior to the SPEO (03/01/2031).

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			identified as a result of the supplemental one-time inspections, additional inspections will be conducted in accordance with the site's corrective action process. This will include one additional penetration with dissimilar metal welds associated with greater than 140°F stainless steel piping systems for each Unit until cracking is no longer detected. Periodic inspection of subject penetrations with dissimilar metal welds for cracking will be added to the PSL ASME Section XI, Subsection IWE AMP if necessary, depending on the inspection results. e) Augment existing procedures to implement a one-time supplemental volumetric inspection of metal shell surfaces that samples randomly selected as well as focused locations susceptible to loss of thickness due to corrosion from the inaccessible side if triggered by plant-specific OE identified through code inspections after the date of issuance of the first renewed license for each unit. This sampling is conducted to demonstrate, with 95% confidence, that 95% of the accessible portion of the metal shell is not experiencing greater than 10% wall loss.	
33	ASME Section XI, Subsection IWF (19.2.2.30)	XI.S3	Continue the existing PSL ASME Section XI, Subsection IWF AMP, including enhancement to: a) Identify the population of ASME Class 1, 2, and 3 high-strength structural bolting greater than one-inch nominal diameter within the boundaries of IWF-1300. b) 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. c) Augment existing procedures to specify the use of high-strength bolt storage requirements discussed in Section 2 of RCSC	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035 Start the one-time inspection no earlier than 5 years prior to the SPEO (03/01/2031).

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			(Research Council for Structural Connections) publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts," for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts. d) 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. e) Augment existing procedures to specify that accessible sliding surfaces are monitored for significant loss of material due to wear and accumulation of debris or dirt. f) 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. g) Augment existing procedures to specify that, for component supports with 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. A representative sample of bolts will be inspected during the inspection interval prior to the start of the SPEO and in each 10-year period during the SPEO. The sample will be 20% of the population (for a material / environment combination) up to a maximum of 25 bolts. h) 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.	

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			i) 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; and • Cracked or sheared bolts, including high-strength bolts, and anchors.	
34	10 CFR Part 50, Appendix J (19.2.2.31)	XI.S4	Continue the existing PSL 10 CFR Part 50, Appendix J AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
35	Masonry Walls (19.2.2.32)	XI.S5	Continue the existing PSL Masonry Walls AMP, including enhancement to: a) Revise the implementing procedure to monitor and inspect for gaps between the supports and masonry walls that could potentially impact the intended function or potentially invalidate its evaluation basis. b) Revise the implementing procedure to include specific monitoring, measurement, and trending of 1) widths and lengths of cracks in masonry walls and mortar joints, and 2) gaps between supports and masonry walls. c) Revise the implementing procedure to include specific guidance for the assessment of the acceptability of the widths and lengths of cracks in masonry walls and mortar joints and of gaps between supports and masonry walls, using evaluation bases established in response to IE Bulletin 80-11 to confirm that the degradation	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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			has not invalidated the original evaluation assumptions or impacted the capability to perform the intended functions.	
36	Structures Monitoring (19.2.2.33)	XI.S6	Continue the existing PSL Structures Monitoring AMP, including enhancements to: a) Monitor and inspect steel edge supports on masonry walls. b) Specify the use of high-strength bolt storage requirements discussed in Section 2 of the Research Council for Structural Connections publication, "Specification for Structural Joints Using High-Strength Bolts," for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts. c) Inspect concrete structures for increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation. d) Inspect elastomers for loss of material and loss of strength. e) Inspect stainless steel and aluminum components for pitting and crevice corrosion, and evidence of cracking due to SCC. f) Include monitoring and trending of leakage volumes and chemistry for signs of concrete or steel reinforcement degradation if active through-wall leakage or groundwater infiltration is identified. g) Include tactile inspection in addition to visual inspection of elastomeric elements to detect hardening. h) Include evidence of water in-leakage as a finding requiring further evaluation. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessment may include	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the water. i) Address the aggressive groundwater/soil environment to account for the extent of the degradation experienced. Specific requirements include evaluations, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed 5 years. j) Require inspections of the Condensate Storage Tank (CST) and Auxiliary Feedwater (AFW) Structures and Piping Inspections in the Trenches every third refueling outage, which will ensure that these inspections are performed at least once per 5 years.	
37	Inspection of Water-Control Structures Associated with Nuclear Power Plants (19.2.2.34)	XI.S7	Continue the existing PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP, including enhancement to: a) Revise the implementing procedure to specify the use of high-strength bolt storage requirements discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts. b) Revise the implementing procedure to state that further evaluation of evidence of groundwater infiltration or through-concrete leakage may also include destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels, and that assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the leakage water if leakage volumes allow.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			c) Revise the severe weather implementing procedure to include performance of structural inspections after major unusual events such as hurricanes, floods, or seismic events.	
38	Protective Coating Monitoring and Maintenance (19.2.2.35)	XI.S8	Continue the existing PSL Protective Coating Monitoring and Maintenance AMP, including enhancement to: a) Ensure the implementing documents reference ASTM D5163-08 and clarify the parameter monitored to include blistering, cracking, rusting or physical damage. b) Ensure any follow-up inspections are performed by individuals trained and certified in the applicable reference standards of ASTM Guide D5498-12. c) Ensure inspections include the specific inspection and documentation parameters and observation and testing methods listed in ASTM D5163-08 subparagraph 10.2.1 through 10.2.6, 10.3, and 10.4. d) Ensure implementing documents reference the guidance of Regulatory Position C4 of RG 1.54 Revision 3.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

Table 19-3
List of Unit 1 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
39	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (19.2.2.36)	XI.E1	Continue the existing PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (formerly the Containment Cable Inspection Program), 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, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035 Implement the AMP and start the 10-year interval inspections no earlier than 10 years prior to the SPEO (03/01/2026).
40	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits (19.2.2.37)	XI.E2	Implement the new PSL 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, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
41	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (19.2.2.38)	XI.E3A	Implement the new PSL Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP including the following: a) Perform medium-voltage cable testing on lead-sheathed (submarine) cables, as a one-time test. b) Perform manhole inspections (containing medium-voltage cables in the program) for water accumulations, cable structural supports' integrity, sump pump operability verification, and manhole drainage path integrity on at least an annual basis.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

Table 19-3
List of Unit 1 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			c) Perform manhole inspections (containing medium-voltage cables in the program) following a major water event for water accumulations, sump pump operability verification (and associated alarms), and manhole drainage path integrity. d) Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms).	
42	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (19.2.2.39)	XI.3B	Implement the new PSL Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP including the following: a) Perform sample I&C cable visual inspection and tests (if necessary) at least every six years. b) Perform manhole inspections (containing I&C cables in the program) for water accumulations, cable structural supports' integrity, sump pump operability verification, and manhole drainage path integrity on at least an annual basis. c) Perform manhole inspections (containing I&C cables in the program) following a major water event for water accumulations, sump pump operability verification (and associated alarms), and manhole drainage path integrity. d) Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

Table 19-3
List of Unit 1 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms).	
43	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (19.2.2.40)	XI.E3C	Implement the new PSL Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP including the following: a) Perform periodic manhole inspections to prevent inaccessible in-scope low-voltage power cables from being exposed to water accumulations in low-voltage power cable manholes, vaults, and conduits and removing water, as needed, but at least once every year. Inspections are also to be performed after event-driven occurrences, such as heavy rain or flooding. 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 to be inspected, and their operation verified periodically. b) Perform periodic visual inspections of low-voltage power cables accessible from manholes, vaults, or other underground raceways for jacket surface abnormalities at least once every 6 years. c) Perform initial low-voltage power cable testing on a sample population to determine the condition of the electrical insulation. One or more tests may be required based on cable type, application, and electrical insulation material to determine the age-related degradation of the cable insulation. Inaccessible low-voltage power cables designed for continuous wetting or submergence are also included in this AMP. The need for additional periodic tests and inspections is determined by the test /inspection results as well as industry and plant-specific OE.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

Table 19-3
List of Unit 1 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			d) Inspect manholes equipped with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms).	
44	Metal Enclosed Bus (19.2.2.41)	XI.E4	Implement the new PSL Metal Enclosed Bus AMP	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PSL1: 09/01/2035
45	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (19.2.2.42)	XI.E6	Implement the new 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, or no later than the last refueling outage prior to the SPEO, i.e.: PSL1: 09/01/2035
46	High-Voltage Insulators (19.2.2.43)	XI.E7	Implement the new High-Voltage Insulators AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
47	Pressurizer Surge Line (19.2.2.44)	N/A – PSL Site-Specific Program	Continue the existing PSL Pressurizer Surge Line AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035

Table 19-3
List of Unit 1 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
48	Nonsafety-related SSCs that are not Directly Connected to Safety-related SSCs but have the Potential to Affect Safety- Related SSCs Through Spatial Interactions Screening Document	N/A	Minimize the potential for indoor abandoned equipment outside containment to leak or spray on safety-related equipment by performing the following: a) Update plant procedures to require the periodic venting and draining of indoor abandoned equipment located outside containment that is directly connected to in-service systems. b) Verify that abandoned equipment that is no longer directly connected to in-service systems is vented and drained.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
49	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 corresponding aging management recommendations, including: a) Evaluate their applicability to the PSL Unit 1 primary shield wall and associated reactor vessel supports. b) Update design calculations, as appropriate. c) Develop an informed site-specific program, if needed.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL1: 09/01/2035
50	Quality Assurance Program (19.1.3)	Appendix A	Continue the existing FPL QA Program at PSL.	Ongoing
51	Operating Experience Program (19.1.4)	Appendix B	Continue the existing PSL OE Program.	Ongoing

Appendix A1
USFAR Markup

This section provides a markup of the PSL Unit 1 UFSAR delineating UFSAR changes that will be required for subsequent license renewal.

1.2.3 OPERATING CHARACTERISTICS AND SAFETY CONSIDERATIONS

1.2.3.1 Nuclear Steam Supply System

The reactor core is fueled with uranium dioxide pellets enclosed in Zirconium alloy tubes with welded end plugs. The tubes are fabricated into assemblies in which end fittings prevent axial motion and grids prevent lateral motion of the tubes. The control element assemblies (CEAs) consist of Inconel clad boron carbide absorber rods which are guided by Zirconium alloy tubes located within the fuel assembly. The core consists of 217 fuel assemblies loaded with multiple U-235 enrichments.

The reactor vessel and its closure head are fabricated from manganese moly steel internally clad with stainless steel. The vessel and its internals are designed so that the integrated neutron flux (E > 1 Mev) at the vessel wall will be less than ~~4.7~~6.38 x 10^{19} n/cm^2 over an 80~~60~~-year period.

The internal structures include the core support barrel, the core support plate, the core shroud, and the upper guide structure assembly. The core support barrel is a right circular cylinder supported from a ring flange from a ledge on the reactor vessel. The flange carries the entire weight of the core. The core support plate transmits the weight of the core to the core support barrel by means of vertical columns and a beam structure. The core shroud surrounds the core and minimizes the amount of coolant bypass flow. The upper guide structure provides a flow shroud for the CEAs and prevents upward motion of the fuel assemblies during pressure transients. Lateral motion limiters or snubbers are provided at the lower end of the core support barrel assembly.

The reactor coolant system is arranged as two closed loops connected in parallel to the reactor vessel. Each loop consists of one 42-inch ID outlet (hot) pipe, one steam generator, two 30-inch ID inlet (cold) pipes and two pumps. An electrically heated pressurizer is connected to the hot leg of one of the loops and a safety injection line is connected to each of the four cold legs.

The reactor coolant system operates at a nominal pressure of approximately 2235 psig. The reactor coolant enters near the top of the reactor vessel, and flows downward between the reactor vessel shell and the core support barrel into the lower plenum. It then flows upward through the core, leaves the reactor vessel, and flows through the tube side of the two vertical U-tube steam generators where heat is transferred to the secondary system. Reactor coolant pumps return the reactor coolant to the reactor vessel.

The two steam generators are vertical shell and U-tube units. The steam generated in the shell side of the steam generator flows upward through moisture separators and scrubber plate dryers which reduce the moisture content to less than 0.2 percent. All surfaces in contact with the reactor coolant are either stainless steel or NiCrFe alloy in order to minimize corrosion.

The reactor coolant is circulated by four electric motor driven single-suction vertical centrifugal pumps. The pump shaft leakage is minimized by mechanical seals. Each pump motor is equipped with an anti-reverse mechanism to prevent reverse rotation of any pump that is not in operation.

1.2.3.2 Engineered Safety Features and Emergency Systems

Engineered safety features systems protect the public and plant personnel in the highly unlikely event of an accidental release of radioactive fission products from the reactor system, particularly as the result of a LOCA. The safety features function to localize, control, mitigate, and terminate such accidents to hold exposure levels below applicable limits.

fitted with a double gasketed blind flange in the refueling canal and a standard gate valve in the spent fuel pool. This arrangement prevents leakage through the transfer tube in the event of an accident. The outer pipe is welded to the containment vessel and provision is made for testing welds essential to the integrity of containment. Bellows expansion joints are provided on the pipe to compensate for building settlement and differential seismic motion between the reactor building and the fuel handling building.

The bellows expansion joints meet the requirements of ASME Boiler and Pressure Vessel Code, Section III. The fuel transfer tube bellows are designed for a 35 foot head of water. The static head of water is always less than 35 feet.

Bellows design and construction is such that bellows will not deflect more than its designed amount. The bellows is designed to withstand a 80~~60~~-year lifetime total of 7,000 cycles of expansion and compression due to operating thermal expansion and 200 cycles of differential settlement and seismic motion.

f) Equipment and Personnel Access

Two equipment hatches are provided. These are welded steel assemblies with 28'-0" diameter and 12'-0" diameter clear openings respectively. The 28'-0" diameter hatch cover will be welded back into position upon completion of construction. The design is such that post-weld heat treatment is not required.

The 12'-0" diameter hatch has a double gasketed flanged and bolted cover. Provision is made to pressurize the space between the gaskets to 44 psig.

Two personnel air locks are provided. These are welded steel assembles. Each lock has two double gasketed doors in series. Provision is made to pressurize the space between the gaskets. The doors are mechanically interlocked to ensure that one door cannot be opened until the second door is sealed. Provisions are made for deliberately violating the interlock by the use of special tools and procedures under strict administrative control. Each door is equipped with quick acting valves for equalizing the pressure across the doors. The doors will not be operable unless the pressure is equalized. Pressure equalization is possible from every point at which the associated door can be operated. The valves for the two doors are properly interlocked so that only one valve can be opened at one time, and only when the opposite door is closed and sealed. Each door is designed so that with the other door open, it will withstand and seal against design and testing procedures of the containment vessel. There is visual indication outside each door showing whether the opposite door is open or closed and whether its valve is open or closed. In addition, limit switches are provided to indicate remotely whether doors are open or closed. Control room annunciation is provided for indication of the Personnel Airlock. Status of the Emergency Escape Air Lock is provided on the security display panel. Provision is made outside each door for remotely closing and latching the opposite door so that in the event that one door is accidentally left open it can be closed by remote control. The air-locks have nozzles installed which will permit pressure testing of the lock at any time.

An interior lighting system and a communications system are installed.

3.9.2 ASME CODE CLASS II AND III COMPONENTS

3.9.2.1 Design Conditions

The design pressure, temperature and other conditions that were considered in the design of each system containing Code Class 2 or 3 mechanical components are listed in Table 3.9-4.

3.9.2.2 Design Loading Combinations

The design loading combinations considered in the component design are: normal (operating design) pressure, temperature and thrust loads combined with seismic, hurricane or tornado loads. Seismic loads and hurricane and tornado loads are not assumed to act concurrently. The design loading conditions are categorized as design, normal, upset, emergency, and faulted. The stress limits associated with each of the design loadings categories Code Class 2 or 3 components are given in Table 3.9-3A, and for piping in Table 3.9-3.

The forces and moments acting on any component in the piping system are supplied to the manufacturer so that it can be insured that the component will function under the applied loads

Loads resulting from transients appropriate to specified plant operating conditions have been considered and accommodated by design. These conditions have been analyzed in accordance with applicable code requirements as an independent case. The transient operating conditions accounted for in the design of the reactor coolant pressure boundary (NSS vendor's scope) is provided in Section 5.2.1.2. Cyclic loading considerations for equipment outside the NSS vendor's scope is discussed below.

The ASME code does not require cyclic analyses for Class 2 and 3 components. Equipment specifications for pumps specify "maximum" moments and forces at the pump nozzles. These maximum moments and forces envelop operating transient loading conditions appropriate for the component. (See Table 3.9-3A footnote 2). For Class 2 and 3 piping the dynamic conditions resulting from fast valve closure and relief valve operation are analyzed as shown in loading combination 3 of Table 3.9-3. These dynamic conditions envelop the operating transients.

For Class I piping and fitting assemblies, fatigue analysis has been performed to ensure the usage factor is adequate for the 80~~60~~-year design life. The applicable transients have been assigned operating condition categories, normal (N), upset (U), test(T), emergency (E), or faulted (F). Cyclic loading combinations considered for Class I piping and assemblies include:

Operating Condition Category	Operating	Occurrences
N	k – Purification	1,000
N	l – Low Volume Control & Makeup	2,000
N	m – Boric Acid Dilution	8,000
U	n – Loss of Charging Flow	200
U	o – Loss of Letdown	~~50~~ 500
U	p – Regenerative HX Isolation Long Term	80
U	q – Regenerative HX Isolation Short Term	40

C. Safety Injection Supply Lines

The safety injection lines I-6-SI-110, 111, 112, 113, I-12-RC-151, 152, 153, 154 from valves V3114, V3124, V3134 and V3144 to the appropriate cold leg nozzle are each as a normal operating condition subject to five hundred (500) injections of 200°F water into the primary coolant cold leg piping initially at 300°F with a system pressure of 300 psia or less at a rate of 1500 gpm per nozzle. (from low pressure safety injection pumps)

As an "Emergency" operating condition, the safety injection lines:

I-3/4-SI-114, 115, 116, 117	Instrument Lines
I-3-SI-137, 138, 139, 140	HP & Aux HP Lines
I-2-SI-126, 143, 145, 147	HP & Aux HP Lines
I-6-SI-110, 111, 112, 113 I-12-RC-151, 152, 153, 154	Safety Injection Lines
I-1-SI-227 thru 246	Vent & Drains

covering the high pressure and auxiliary high pressure headers from valves V3113, V3123, V3133 and V3143 through the appropriate cold leg nozzle may be subject to five (5) injections of 120°F water into the reactor coolant cold leg piping initially at 551°F with a system pressure of 1240 psia or less at a rate of 225 gpm per nozzle for 90 seconds followed by 40°F water from High Pressure Safety Injection Pumps.

The safety injection tank discharge lines I-12-SI-148, 149, 150, 151, I-6-SI-110, 111, 112, 113 and I-12-RC-151, 152, 153, 154 from the check valves below the tanks to the cold leg nozzles will, as a faulted condition, be subject to one (1) injection of 100°F water into the primary coolant cold leg piping initially at 551°F with a system pressure in excess of 230 psig or less at a rate of 19,000 gpm per nozzle. Flow decreases linearly over 25 seconds to 2000 gpm per nozzle (from safety injection tanks).

Following the above flow at 40°F from the low pressure safety injection headers through the safety injection lines to the cold leg nozzles will be maintained at 2000 gpm per line (from low pressure safety injection pumps)until equilibrium is reached. This is a "faulted" operating condition.

d. Safety Injection Return Lines

The safety injection return lines (I-1-SI-118, I-1-SI-120, I-1-SI-123 and I-1-SI-125) are subject to 2000 occurrences of a step change from 130°F and 1100 psia to 120°F and 200 psia. This transient occurs upon opening the return line pneumatic valves to relieve the pressure accumulated between the safety injection check valves (V3113, V3114 and V3217 typical). The flow rate varies from 0 to 40 gpm during those step changes. This transient occurs periodically during the operation of the plant.

e. Shutdown Cooling Suction Lines

The shutdown cooling suction lines, I-12- RC-147 and 162, I-10SI-127 and 130, as a normal operating condition, be subject to 500 occurrences of shutdown cooling with a flow of 3000 gpm, an initial temperature of 350°F max and pressure and temperature varying as appropriate for cooldown beyond 350 °F.

f. Letdown Line

Five hundred (500) heat-up cycles with a flow of 80 gpm and temperature increasing at 100°F/hr from 70°F to 550°F and pressure increasing from atmospheric to 2250 psia over this period. This condition should be considered as a "normal" operating condition.

Five hundred (500) cooldown cycles of flow at 29 gpm and temperature decreasing from 550°F to 140°F at a rate of 100°F/hr and pressure decreasing from 2250 psia to atmospheric. This condition should be considered as a "normal' operating condition.

Operating Condition Category	Plant Conditions	Occurrences
N	a – Heatup, 100°F/hr	500
N	b – Cooldown, 100°F/hr	500
N	c – Loading, 5%/min.	15,000
N	d – Unloading, 5%/min.	15,000
N	e – Step Load Increase, +10%	2,000
N	f – Step Load Decrease, -10%	2,000
U	g – Reactor Trip	400
U	h – Loss of Reactor Coolant System Flow	40
U	i – Loss of Turbine-Generator Load	40
E	j – Loss of Secondary Pressure	5
N	k – Purification	1,000
N	l – Low Volume Control & Makeup	2,000
N	m – Boric Acid Dilution	8,000
U	n – Loss of Charging Flow	200
U	o – Loss of Letdown	~~50~~ 500
U	p – Regenerative Hx Isolation Long-term	150
U	q – Regenerative Hx Isolation Short-term	40

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CHAPTER 4

LIST OF TABLES

Near the bottom of the extension shaft is a larger diameter section which allows the upper guide structure to pick up the extension shafts as the upper guide structure is removed from the reactor vessel.

The drive shaft is a long tube made of 304 stainless steel. It is threaded and pinned to the extension shaft. The drive shaft has circumferential notches along the shaft to provide the means of engagement to the control element drive mechanism.

The magnet assembly consists of a housing, magnet and plug. Two, 2-inch cylindrical Alnico-V magnets with a minimum flux density of 325 gauss are used in the assembly. This magnet assembly is used to actuate the reed switch position indication. The magnets are contained in a housing which is plugged at the bottom. The housing provides a means of attaching the lifting tool for disengaging the CEA from the extension shaft.

In order to engage or disengage a CEA to or from the extension shaft, a special gripper operating tool is attached to the top of the extension shaft assembly when the reactor vessel head has been removed. One part of the tool is attached to the extension sleeve to hold this portion of the extension shaft assembly fixed. Another part of the tool is attached to the operating rod at the magnet assembly and is used to raise the operating rod to conform to the pattern of the slot in the extension sleeve. Withdrawing of the operating rod raises the plunger which in turn allows the fingers of the collet type gripper to collapse to a smaller diameter and allows separation of the extension shaft assembly from the CEA.

4.2.3.1.3 Design Evaluation

(a) Prototype Tests

A prototype magnetic jack type standard CEDM was subjected to accelerated life tests accumulating 100,000 feet of travel. ~~equivalent to a 60-year lifetime.~~

The first phase of the accelerated life test consisted of continuous operation of the mechanism at 40 in/min over a 137 inch stroke lifting and lowering 230 pounds for a total travel of 32,500 feet. This test was performed at simulated normal reactor operating conditions of 600°F and 2200 psig. Upon completion of the test, the motor bearing surfaces were inspected and measured. A maximum bearing wear of .003-inch was measured. This degree of wear is considered acceptable. ~~based on the 60-year design life.~~

4.3.2.9 Vessel Irradiation

The design of the reactor internals and of the water annulus between the active core and vessel wall is such that the peak vessel neutron fluence at ~~60~~ 80 years ~~at 2700 MWth~~ is calculated to be ~~less than 4.7~~approximately 6.38 x 10^{19} n/cm^2(E > 1MeV). The neutron fluence at the limiting vessel material, longitudinal weld seams 3-203 at the 15°, 135° and 255° azimuthal locations, at 80 years is approximately 3.88 x 10^{19} n/cm^2 (Reference 10) . The 80 year SLR fluence projections include a 10% factor of conservatism for future cycles beyond the end-of-cycle 30.~~at 60 years is less than 3.1 x 10^{19} n/cm^2.~~

~~The EPU would normally result in an increase to the neutron fluence on the reactor pressure vessel. There was actually a small decrease in the projected 60-year fluence based on 52 EFPH; this is seen in Table 4.3-17. This decrease occurred because the EPU fluence analysis used more recent core power histories that enabled removal of excess conservatism from the pre-EPU 60-year fluence analysis, while adding a 10% factor of conservatism to the EPU fluence projections beginning with Cycle 25. The effect of the projected changes in operating conditions on reactor vessel integrity was evaluated. The vessel fluence projections for the St. Lucie Unit 1 plant life of 60 years are presented in Table 4.3-18. The 0° and 15° azimuths correspond to the peak fluence locations for the base metal and circumferential weld (0°) and the axial welds (15°). Vessel fluence is provided for the vessel inside surface (cladbase metal interface) and for the ¼ and ¾ thickness (t) locations. (Reference 9)~~

~~The limiting material is the longitudinal weld seam 3-203 at the 15°, 135° and 255° azimuthal locations with a maximum adjusted RT_{NDT} at 60 years that is below the 10 CFR 50.61 screening limit.~~

4.3.2.10 References for Section 4.3.2

1. XN-75-27(A), Supplement 1, September 1976.

2. XN-75-27(A), Supplement 2, December 1977.

3. XN-75-27(A), Supplement 3, November 1980.

4. XN-NF-84-12, "St Lucie Unit 1 Cycle 6 Safety Analysis Report Reload Batches XN-1 and XN-IA", Exxon Nuclear Company, February 1984.

5. XN-CC-28, Revision 5, "XTG - A Two Group Three-Dimensional Reactor Simulator Utilizing Coarse Mesh Spacing", Exxon Nuclear Company, July 1979.

6. XN-75-27(A), "Exxon Nuclear Neutronics Design Methods for Pressurized Water Reactors", Exxon Nuclear Company, June 1975.

7. XN-75-27(A), Supplement 4, December 1985

8. WCAP-11596-P-A, “Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, “ June 1988 (Westinghouse Proprietary)

9. WCAP-17389-P, “St. Lucie Unit 1 Extended Power Uprate (EPU) Engineering Report”, February 2011, (Westinghouse Proprietary)

10. WCAP-18609-NP Rev 2, “St. Lucie Units 1 & 2 Subsequent License Renewal: Time Limiting Aging Analysis on Reactor Vessel Integrity”, July 2021

4.3.3 COMBUSTION ENGINEERING ANALYTICAL METHODS (CYCLES 1-5)

4.3.3.1 Reactivity and Power Distribution

4.3.3.1.1 Method of Analysis

The nuclear design analysis for low enrichment PWR cores is based on a combination of multigroup neutron spectrum calculations, which provide cross sections appropriately averaged over a few broad energy groups, and few-group one, two, and three dimensional diffusion theory calculations of integral and differential reactivity effects and power distributions. The multigroup calculations include

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TABLE 4.3-14

COMPARISON OF CALCULATED AND
MEASURED DROPPED AND
EJECTED ROD WORTHS, %Δρ

		Measured	Calculated
A.	Palisades		
	Ejected Rods		
	1. corner Rod from 9 rod pattern*	0.27	0.25
	2. corner Rod from 13 rod pattern	0.64	0.71
B.	Maine Yankee		
	Ejected Rods		
	1. center Rod from 9 rod pattern	0.13	0.15
	2. corner Rod from 29 rod pattern	0.33	0.27
	Dropped Rods		
	3. central dual with bank 5 in	0.14	0.15
C.	Omaha		
	Ejected Rod		
	1. peripheral rod from zero power PDIL	0.28	0.29
	Dropped Rod		
	2. peripheral dual from full power PDIL	0.15	0.14
	3. more central dual from full power PDIL	0.19	0.18

* 5 rods inserted 50%, others bottomed

~~TABLE 4.3-17~~

~~Comparison of Peak 0° and 15° Azimuth Vessel ID Fluence Values at 52 EFPY~~		
~~Source~~	~~Azimuthal Location~~	~~Surface (n/cm2, E > 1.0 MeV)~~
~~Pre-EPU~~	~~0°~~	~~4.24E+19~~
~~EPU analysis~~	~~0°~~	~~4.036E+19~~
~~Pre-EPU~~	~~15°~~	~~2.81E+19~~
~~EPU Analysis~~	~~15°~~	~~2.630E+19~~

~~TABLE 4.3-18~~

~~EFPY~~	~~Azimuthal Location~~	~~Fluence at Clad-Base Metal Interface (n/cm2, E>1.0 MeV)~~	~~¼ t Fluence (n/cm2,E>1.0 MeV)~~	~~¾ t Fluence (n/cm2,E>1.0 MeV)~~
~~35~~	~~0°~~	~~2.573E+19~~	~~1.534E+19~~	~~5.448E+18~~
~~35~~	~~15°~~	~~1.659E+19~~	~~9.888E+19~~	~~3.512E+18~~
~~52~~	~~0°~~	~~4.036E+19~~	~~2.405E+19~~	~~8.545E+18~~
~~52~~	~~15°~~	~~2.630E+19~~	~~1.567E+19~~	~~5.568E+18~~
~~54~~	~~0°~~	~~4.208E+19~~	~~2.508E+19~~	~~8.909E+18~~
~~54~~	~~15°~~	~~2.744E+19~~	~~1.635E+19~~	~~5.810E+18~~

4.3-61 Amendment No. ~~26 (11/13)~~ Later

5.2.1.1 Functional Performance Requirements

The function of the reactor coolant system is to remove heat from the reactor core and transfer it to the secondary system by the forced circulation of pressurized borated water. The borated water serves both as a coolant and neutron moderator. The reactor coolant system is designed for the normal operation of transferring 3034 MWt from the reactor core (3020 MWt) and reactor coolant pumps (14 MWt) to the steam generators.

The reactor coolant system also serves as a pressure boundary having a high degree of leak tightness. The integrity of this pressure boundary is assured by appropriate recognition of operating, seismic and/or accident stress loadings. The normal operating pressure of the reactor coolant system is approximately 2235 psig.

The system design temperature and pressure are conservatively established and exceed the combined normal operating value and those resulting from anticipated transients. The effects of instrument error and the response characteristics of the control system are included in the design rating of the systems. The change due to the anticipated transients also considers the effect of reactor core thermal lag, coolant transport time, system pressure drop and the characteristics of the safety and relief valves.

Test pressures for the system and individual components are in accordance with the codes given in Table 5.2-1. The ASME Code specifies that the hydrostatic test pressure shall be 125 percent of design pressure. The allowable number of such tests are limited to those allowed by usage factor analyses.

5.2.1.2 Transients Used in Design and Fatigue Analyses

EC289971

The relocated TS component cyclic or transient limits table is contained in Table 5.2-1a.

The following design cyclic transients, which include conservative estimates of the operational requirements for the components, were used in the fatigue analyses required by the applicable codes listed in Table 5.2-1. (Note: Differences exist between the cycles and transients assumed in the design of Unit 1 and those assumed in the design of Unit 2. Further, there may also be unit differences with respect to those cycles and transients required by plant procedure to be tracked). The evaluation for a 80~~60~~-year plant design life concludes the design cycles listed below, which were based on a 40-year design life, envelope the 80~~60~~-year plant design life. See Section ~~18.3.2.1~~19.3.3.1.

a) 500 heatup and cooldown cycles during the design life of the components in the system with heating and cooling at a rate of 100°F/hr. between 70°F and 532°F (653°F for the pressurizer). This is based on a normal plant cycle of one heatup and cooldown per month rounded to the next highest hundred. The heatup and cooldown rate of the system is administratively limited to a value that will assure that these limits will not be exceeded.

b) 15,000 power change cycles over the range of 15 percent to 100 percent of full load at 5 percent of full load per minute increasing and decreasing. This is based on a normal plant operation involving one cycle per day for 40 years rounded to the next highest 1000.

TABLE 5.4-3

CAPSULE REMOVAL SCHEDULE (~~5~~d)

Vessel Location ~~on Vessel Wall~~	~~Approximate Removal Schedule~~ Capsule Withdrawal EFPY (e)	Capsule~~Predicted~~ Fluence n/cm², E > 1.0 MeV	Lead Factor (~~3~~b)
97° (~~1~~a)	~~4.67~~ 4.82	~~5.174~~ 5.09 x 10^{18}	~~------~~1.35
104° (~~1~~a)	~~9.515~~ 9.70	~~7.885~~ 7.70 x 10^{18}	~~------~~ 0.83
284° (~~1~~a)	~~17.23~~ 17.42	~~1.243~~ 1.22 x 10^{19}	~~------~~ 0.88
263° (f)	~~38~~ 47	~~3.79~~ 4.60 x 10^{19}	1.~~34~~23
83° ~~(2)(4)~~	~~45~~ 62	~~4.60~~ 6.38 x 10^{19}	1.~~34~~23
277° (~~4~~c)	Standby (c)	------	1.~~34~~23

Notes:

(~~1~~a) Numbers for these capsules are actual. Fluence values reflect the most recent analysis ~~(reference 13)~~.

~~(2) The fifth capsule is not required to be tested per ASTM E185. It is reserved as a standby should an additional license period be considered.~~

(~~3~~b) Lead Factor is defined as the capsule fluence divided by RV base metal peak fluence.

(~~4~~c) ~~The capsule removal times were switched for the 83° and 277° capsules.~~ The capsule at 277° was found to be missing its ACME threaded top during a 1996 vessel inspection (Condition Report 96-1064). Without the top, a special removal tool will be required to retrieve the 277° capsule. This capsule may be substituted for either Capsule 83° or 263° if tooling capable of removing this capsule is developed, since it is considered to be radiologically equivalent to Capsules 83° and 263° (also at the 7° azimuthal location).~~Both capsules contain identical samples and receive similar fluence since they are 180° apart.~~

(~~5~~d) Capsule removal schedule changes require NRC approval per 10 CFR 50, Appendix H.

(e) For capsules not yet withdrawn, the capsule will be withdrawn at the outage nearest to but following the stated EFPY.

(f) Based on Unit 1 UFSAR Table 5.4-2, Capsule 263° contains Standard Reference Material (SRM) in lieu of the transverse base metal Charpy specimens. It is recommended that this capsule be withdrawn prior to achieving the SLR in order for the SLR capsule to contain as many specimens as possible which are representative of St. Lucie Unit 1 reactor vessel material.

Operating procedure restrictions and design features are provided so that the normal safety injection system lineup is not altered except under reduced reactor coolant system pressure conditions. Valve interlocks on the suction line to the low pressure safety injection pumps preclude initiation of shutdown cooling until pressurizer pressure is below 267 psia. System alignment will not be altered until this low pressure condition is reached. Since several hours must elapse after reactor shutdown before this condition is reached, the required level of core cooling is significantly reduced. Therefore, in the event of a pipe break with the system in the shutdown cooling mode, sufficient time exists for operator action to safely control the accident.

This shutdown procedure will occur at most a few times per year. For each shutdown, there is a period of about 25 hours during which automatic initiation of the ECCS is not available, the time required to reduce temperature to the refueling temperature.

6.3.3.3 Service Environment

All safety injection, system components and associated electrical equipment have been examined with regard to capability to withstand post-accident environmental conditions. The design of each component has been determined that the design criteria encompass the most severe condition the equipment will encounter.

Components such as remotely operated valves, and instrumentation and control equipment located within the containment required for initiation of safety injection system operation are designed to withstand the post-accident containment conditions of temperature, pressure, humidity, chemistry and radiation for the time period required.

All other safety injection components required to maintain a functional status have been located outside containment to eliminate exposure of this equipment to the post-LOCA containment conditions. The equipment outside containment (i.e., reference to Figure 6.3-2 indicates location of equipment inside or outside of containment) is designed in consideration of the chemical and radiation effects associated post-LOCA operation.

Design pressures and temperatures are in excess of the maximum pressures and temperatures seen during normal operating or accident conditions. Materials of construction for the pumps are compatible with the expected water chemistry under LOCA conditions. A radiation resistance requirement (10^7rads) has also been placed on the pumps, which is in excess of the calculated dose based on plant operation of 80~~60~~ years plus a LOCA. All power operated valves in the safety injection system which might require operation in the post-LOCA period are located outside containment and are designed in consideration of the attendant spray and radiation environment.

Section 3.11 contains additional discussion concerning the environmental design of mechanical and electrical equipment.

TABLE 9.3-9

DESIGN TRANSIENTS
Regenerative and Letdown Heat Exchangers

Transient	Cycles in 80~~60~~ Years	Variation Level Initial -	Final	Rate	Letdown Flow Initial - Final (GPM)	Charging Flow (GPM)
Step Power Change	2000	90% -	100%		40 - 89 (100 sec) 89 - 40 in 11.7 min	44
Step Power Change	2000	100% -	90%		40 - 29; 29 - 40	44 (88 2.8 min)
Ramp Power Change	15000	15% -	100%	5%/min	40 - 128 in 16 min 128 - 40 in 17 min	44
Ramp Power Change	15000	100% -	15%	5%/min	40 - 29; 29 - 40 in 27 min	44-88-132; 132-88-44 in 19 min
Reactor Trip	440	100% -	0%		40 - 29; 29 - 40 in 30 min	44-88-132; 132-88-44 in 22 min
Loss of Load	45	100% -	0%		40 - 116-29; 29 - 40 in 28.3 min	44-88-132; 132-88-44 in 20 min

TABLE 9.3-9 (Cont'd)

Transient	Cycles in 80~~60~~ Years	Variation Level Initial - Final	Rate	Letdown Flow Initial - Final (GPM)	Charging Flow (GPM)
Maximum Purification	1000			40-128; 128-40	44-88-132; 132-88-44
Loss of Charging	100	-		40 - 0 0 - 40	44-0 0-44
Loss of Letdown	50	-		40 - 0 0-128-40 15 min after restart	44
Short Term Isolation Regen. Ht. Exch.	400	-		40 - 0 0 - 40	44-0 0-44
Long Term Isolation Regen. Ht. Exch.	800			40 - 0 0 - 40	44-0 0-44
Boron Dilution	10,000	-		40 - 128 128-40	44-132 132-44

APPENDIX A2

UNIT 2 UPDATED FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

TABLE OF CONTENTS

LIST OF TABLES

19.0 Aging Management Programs and Time-Limited Aging Analysis Activities

19.1 Introduction

The application for a renewed operating license for Unit 2 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 PSL Subsequent License Renewal Application (SLRA) and includes the following sections:

- Section 19.1.1 contains a listing of the PSL 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 is also one site-specific AMP for PSL, the Pressurizer Surge Line AMP (Section 19.2.2.44).
- Section 19.1.2 contains a listing of the time-limited aging analyses (TLAAs).
- Section 19.1.3 contains a discussion stating the relationship between the Florida Power & Light Company (FPL) Quality Assurance (QA) Program at PSL and the AMPs' corrective actions, confirmation process, and administrative controls elements.
- Section 19.1.4 contains a summary of the PSL Operating Experience (OE) Program.
- Section 19.2 contains a summary of the PSL programs used for managing the effects of aging. These AMPs are associated with either NUREG-2191 Chapter X or Chapter XI.
- Section 19.3 contains a summary of the TLAAs applicable to the SPEO.
- Section 19.4 contains the PSL 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.

19.1.1 Aging Management Programs

AMPs for PSL SLR are listed in Table 19-1 and described in Section 19.2. The AMPs are listed chronologically as they appear in NUREG-2191, with the Chapter X AMPs first, followed by the Chapter XI AMPs and ending with the site-specific Pressurizer Surge Line AMP. The PSL AMPs are categorized as either existing AMPs or new AMPs for SLR. The existing PSL AMPs are renamed and enhanced as necessary to more closely align with AMPs described in NUREG-2191.

Table 19-1 reflects the status of the PSL AMPs at the time of the SLRA submittal. Regulatory commitments, which include AMP enhancements and implementation schedules for PSL AMPs are identified in the PSL SLR Commitment List within Section 19.4.

Table 19-1
List of PSL Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
X.M1	Fatigue Monitoring (Section 19.2.1.1)	Existing
X.M2	Neutron Fluence Monitoring (Section 19.2.1.2)	Existing
X.S1	Concrete Containment Unbonded Tendon Prestress (PSL U2 containment does not have prestressed tendons.)	N/A
X.E1	Environmental Qualification of Electric Equipment (Section 19.2.1.9)	Existing
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section 19.2.2.1)	Existing
XI.M2	Water Chemistry (Section 19.2.2.2)	Existing
XI.M3	Reactor Head Closure Stud Bolting (Section 19.2.2.3)	Existing
XI.M4	BWR Vessel ID Attachment Welds (PSL U2 is a PWR.)	N/A
XI.M5	(Deleted from NUREG-2191.)	N/A
XI.M6	(Deleted from NUREG-2191.)	N/A
XI.M7	BWR Stress Corrosion Cracking (PSL U2 is a PWR.)	N/A
XI.M8	BWR Penetrations (PSL U2 is a PWR.)	N/A
XI.M9	BWR Vessel Internals (PSL U2 is a PWR.)	N/A
XI.M10	Boric Acid Corrosion (Section 19.2.2.4)	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 19.2.2.5)	Existing
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (Section 19.2.2.6)	Existing
XI.M16A	Reactor Vessel Internals (Section 19.2.2.7)	Existing
XI.M17	Flow-Accelerated Corrosion (Section 19.2.2.8)	Existing
XI.M18	Bolting Integrity (Section 19.2.2.9)	Existing
XI.M19	Steam Generators (Section 19.2.2.10)	Existing
XI.M20	Open-Cycle Cooling Water System (Section 19.2.2.11)	Existing
XI.M21A	Closed Treated Water Systems (Section 19.2.2.12)	Existing
XI.M22	Boraflex Monitoring (PSL U2 does not credit Boraflex as a neutron absorber in spent fuel pit criticality analyses.)	N/A
XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section 19.2.2.13)	Existing
XI.M24	Compressed Air Monitoring (Section 19.2.2.14)	Existing

Table 19-1 (continued)
List of PSL Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
XI.M25	BWR Reactor Water Cleanup System (PSL U2 is a PWR.)	N/A
XI.M26	Fire Protection (Section 19.2.2.15)	Existing
XI.M27	Fire Water System (Section 19.2.2.16)	Existing
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks (Section 19.2.2.17)	Existing
XI.M30	Fuel Oil Chemistry (Section 19.2.2.18)	Existing
XI.M31	Reactor Vessel Material Surveillance (Section 19.2.2.19)	Existing
XI.M32	One-Time Inspection (Section 19.2.2.20)	New
XI.M33	Selective Leaching (Section 19.2.2.21)	New
XI.M35	ASME Code Class 1 Small-Bore Piping (Section 19.2.2.22)	Existing
XI.M36	External Surfaces Monitoring of Mechanical Components (Section 19.2.2.23)	Existing
XI.M37	Flux Thimble Tube Inspection (PSL U2 does not use bottom mounted moveable flux thimble tubes.)	N/A
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section 19.2.2.24)	New
XI.M39	Lubricating Oil Analysis (Section 19.2.2.25)	Existing
XI.M40	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (Section 19.2.2.26)	Existing
XI.M41	Buried and Underground Piping and Tanks (Section 19.2.2.27)	New
XI.M42	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section 19.2.2.28)	New
XI.S1	ASME Section XI, Subsection IWE (Section 19.2.2.29)	Existing
XI.S2	ASME Section XI, Subsection IWL (PSL U2 containment does not have prestressed tendons.)	N/A
XI.S3	ASME Section XI, Subsection IWF (Section 19.2.2.30)	Existing
XI.S4	10 CFR Part 50, Appendix J (Section 19.2.2.31)	Existing
XI.S5	Masonry Walls (Section 19.2.2.32)	Existing
XI.S6	Structures Monitoring (Section 19.2.2.33)	Existing
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section 19.2.2.34)	Existing
XI.S8	Protective Coating Monitoring and Maintenance (Section 19.2.2.35)	Existing
XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 19.2.2.36)	Existing

Table 19-1 (continued)
List of PSL 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 19.2.2.37)	New
XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 19.2.2.38)	New
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 19.2.2.39)	New
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section 19.2.2.40)	New
XI.E4	Metal Enclosed Bus (Section 19.2.2.41)	New
XI.E5	Fuse Holders (PSL U2 does 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 19.2.2.42)	New
XI.E7	High-Voltage Insulators (Section 19.2.2.43)	New
N/A – PSL Site-Specific Program	Pressurizer Surge Line (Section 19.2.2.44)	Existing

19.1.2 Time-Limited Aging Analyses

The TLAA summaries applicable to PSL during the SPEO are identified in Table 19-2 and described in the sections subordinate to Section 19.3:

Table 19-2
List of Time-Limited Aging Analyses

Category (Section)	Time-Limited Aging Analyses Name	Section
Reactor Vessel Neutron Embrittlement (19.3.2)	Neutron Fluence Projections	19.3.2.1
	Pressurized Thermal Shock	19.3.2.2
	Upper-Shelf Energy	19.3.2.3
	Adjusted Reference Temperature	19.3.2.4
	Pressure-Temperature Limits and Low Temperature Overpressure Protection (LTOP) Setpoints	19.3.2.5
Metal Fatigue (19.3.3)	Metal Fatigue of ASME Class 1 Components	19.3.3.1
	Metal Fatigue of Non-Class 1 Components	19.3.3.2
	Environmentally-Assisted Fatigue	19.3.3.3
	High-Energy Line Break Analyses	19.3.3.4
Environmental Qualification of Electric Equipment (19.3.4)	Environmental Qualification of Electric Equipment	19.3.4
Containment Liner Plate, Metal Containments, and Penetrations Fatigue (19.3.5)	Containment Liner Plate, Metal Containments, and Penetrations Fatigue	19.3.5
Other Site-Specific TLAAs (19.3.6)	Leak-Before-Break of Reactor Coolant System Loop Piping	19.3.6.1
	Alloy 600 Instrument Nozzle Repairs	19.3.6.2
	Reactor Coolant Pump Flywheel Fatigue Crack Growth	19.3.6.3
	Reactor Coolant Pump Code Case N-481	19.3.6.4
	Crane Load Cycle Limits	19.3.6.5
	Flaw Tolerance Evaluation for Reactor Coolant Loop CASS Piping	19.3.6.6
	Cycle-dependent Fracture Mechanics of Flaw Evaluations	19.3.6.7

19.1.3 <u>Quality Assurance Program and Administrative Controls</u>

The FPL Quality Assurance (QA) Program for PSL implements the requirements of 10 CFR 50, Appendix B, 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 FPL QA Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and NNS 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 FPL QA Program are applicable to all AMPs and activities during the SPEO. The FPL QA

Program procedures, review and approval processes, and administrative controls are implemented, as described in the FPL Topical QA Report, in accordance with the requirements of 10 CFR 50, Appendix B. The FPL QA Program applies to all structures and components (SCs) that have aging effects managed by a PSL AMP. Corrective actions and administrative (document) control for both safety-related and NNS SCs are accomplished in accordance with the established PSL 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.

19.1.4 Operating Experience Program

The PSL OE Program captures the OE from site-specific and industry sources and is systematically reviewed on an ongoing basis in accordance with the FPL 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 PSL 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 PSL OE Program.

19.2 Aging Management Programs

19.2.1 NUREG-2191 Chapter X Aging Management Programs

This section provides UFSAR summaries of the NUREG-2191 Chapter X AMPs associated with TLAAs.

19.2.1.1 Fatigue Monitoring

The PSL Fatigue Monitoring Program 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 TLAAs to provide reasonable assurance that they remain valid in accordance with 10 CFR 54.21(c)(1)(iii). This AMP 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 American Society of

Mechanical Engineers (ASME) Section III, Class 1 cumulative usage factor (CUF) analyses, environmental-assisted fatigue analyses (CUF_{en} analyses), maximum allowable stress range reduction/expansion stress analyses for ASME Section III Class 2, ASME Section III Class 3, and ANSI B31.1 components, ASME III fatigue waiver analyses, high-energy line break, and cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses.

This AMP 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 AMP also sets applicable acceptance criteria (limits) on these parameters and verifies the continued acceptability of existing analyses through cycle counting and parameter monitoring.

The corrective actions specified by the program (e.g., reanalysis, component or structure inspections, or component or structure repair or replacement activities) are taken if the actual number of cycles approaches 80 percent of the analyzed values.

This AMP also relies on the PSL Water Chemistry AMP to provide monitoring of appropriate environmental parameters for calculating environmental fatigue multipliers (F_{en} values).

19.2.1.2 Neutron Fluence Monitoring

The PSL Neutron Fluence Monitoring AMP, previously the fluence and uncertainty calculation portion of the PSL Reactor Vessel Integrity Program, is an existing AMP. This AMP monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to reactor pressure vessel and reactor internal components to provide reasonable assurance 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 AMP is used to verify the continued acceptability of existing analyses through neutron fluence monitoring and 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 performed in a manner that is consistent with Regulatory Guide (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 AMP’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) analyses that are required to be performed in accordance with the 10 CFR Part 50, Appendix G requirements and 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 AMP (Section 19.2.2.19) may provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this AMP. 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.

19.2.1.3 Environmental Qualification of Electric Equipment

The PSL Environmental Qualification of Electric Equipment AMP, previously the PSL Environmental Qualification 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 in-service (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 was 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. The aging evaluations for EQ equipment that specify a qualification of at least 80 years are TLAAs for SLR. The PSL EQ of Electrical Equipment AMP is implemented in accordance with 10 CFR 50.49 and 10 CFR 54.21(c)(1)(iii).

19.2.2 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.

19.2.2.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The PSL ASME Section XI Inservice Inspection, 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, loss of preload, reduction in fracture toughness, and loss of mechanical closure integrity. The AMP consists of periodic volumetric, surface, and/or visual examination of ASME 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 AMP 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 during the subsequent period of extended operation.

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.

19.2.2.2 Water Chemistry

The PSL Water Chemistry AMP, previously known as the Water Chemistry Control Program - Water Chemistry Subprogram, 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 PSL 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. PSL will continue to implement monitoring and control guidance updates from industry guidelines in accordance with NEI 03-08. The PSL Water Chemistry AMP is augmented by the PSL 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).

19.2.2.3 Reactor Head Closure Stud Bolting

The PSL Reactor Head Closure Stud Bolting program is an existing program related to and currently part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program. The PSL Reactor Head Closure Stud Bolting 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.

19.2.2.4 Boric Acid Corrosion

The PSL 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% Zinc (Zn)), that may be adversely affected by some form of borated water leakage. The purpose of this AMP is to provide 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 PSL 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 PSL 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 Acid Inspection Program for Pressurized Water Reactors.”

19.2.2.5 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

The PSL 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 that manages the aging effect of primary water stress corrosion cracking (PWSCC) for pertinent nickel-alloy materials (Alloy 600/82/182) in the reactor coolant system (RCS) pressure boundary. This AMP also addresses OE linked to PWSCC degradation 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 PSL 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.

19.2.2.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

The PSL Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP is an existing AMP. 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. PSL has chosen the component-specific flaw tolerance evaluation method for aging management of Class 1 CASS components.

The Class 1 CASS components for PSL include valve bodies, reactor coolant pump (RCP) casings and RCS piping.

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.

For the Class 1 RCS CASS piping and RCP pump casings, the component specific flaw tolerance evaluations have been updated for the 80-year SPEO as summarized in Section 19.3.6.6.

19.2.2.7 Reactor Vessel Internals

The PSL Reactor Vessel Internals AMP is an existing AMP. The AMP, in accordance with NEI 03-08 requirements, is based on the inspection and evaluation guidelines of EPRI Technical Report No. 3002017168 (MRP-227 Revision 1-A) with a gap analysis that identifies enhancements to the program that are needed to address increasing from a 60 to 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” provided the recommendations for this gap analysis. PSL will continue to implement inspection guidance updates from the industry Issues Programs to manage the aging of the reactor vessel internals in accordance with NEI 03-08. This AMP will be enhanced to implement an NRC-approved version of MRP-227 which addresses 80 years of operation if one is available prior to the SPEO. The PSL program based on MRP-227 Revision 1-A with enhancements identified by MRP 2018-022 is used to manage the applicable age-related degradation mechanisms, listed as follows:

- Cracking, including SCC, IASCC, PWSCC, 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 (IE);
- Changes in dimensions due to void swelling (VS) or distortion; and
- Loss of preload due to thermal and irradiation-enhanced stress relaxation and creep.

19.2.2.8 Flow-Accelerated Corrosion

The PSL 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 which provides reasonable assurance that structural integrity will be maintained between inspections. Additionally, the software tool, FAC Manager, with the erosion module, is used to evaluate components for both FAC and erosion. An erosion basis document has also been developed for future erosion scopes.

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 PSL Flow-Accelerated Corrosion 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 condition. These limited situations are based on site OE and will be monitored similar to other FAC locations that are not modeled. Portions of this activity were previously part of the Pipe Wall Thinning Inspection Program.

19.2.2.9 Bolting Integrity

The PSL Bolting Integrity AMP, previously part of the Systems and Structures Monitoring Program and Periodic Surveillance and Preventative Maintenance Program, is an existing AMP that manages loss of preload, cracking, and loss of material for closure bolting for safety-related and NNS pressure-retaining and other mechanical 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 will 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 kilo-pounds per square inch); lubricant selection (e.g., not allowing the use of molybdenum disulfide); and proper torquing of bolts. T

This AMP will supplement 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, supplemented by volumetric where applicable, are effective in detecting the applicable aging effects, and the frequency of inspection is adequate 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 PSL corrective action program. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspections will include inspection parameters for items such as lighting and distance offset that provide an adequate examination.

Submerged closure bolting that precludes detection of joint leakage will be inspected visually for loss of material during maintenance activities. Bolt heads will be inspected when made accessible and bolt threads will be inspected when joints are disassembled. In each 10-year period during SPEO, a representative sample of bolt heads and threads will be 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 bolts heads and threads per population at each Unit considering the environments of Units 1 and 2 are similar, then the integrity of the bolted joint will be evaluated on a case-by-case basis using methods, such as periodic pump vibration monitoring and trending or operator walkdowns to confirm that sump pumps are appropriately maintaining sump levels.

For bolted joints that contain air or gas, the acceptability of the closure bolting will be evaluated on a case-by-case basis using one of the following methods:

- Inspections performed consistent with that of submerged closure bolting;
- Visual inspections for discoloration (applies when leakage of the environment inside the piping systems would discolor the external surfaces);
- Monitoring and trending of pressure decay when the bolted connection is located within an isolated boundary
- Soap bubble testing; or
- Thermography testing (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 are managed by checking the torque to the extent that the closure bolting is not loose.

High-strength closure bolting [actual measured yield strength greater than or equal to 150 kilo-pounds per square inch (ksi) (1,034 MPa)] may be subject to SCC. For all 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) and closure bolting for which yield strength is unknown, volumetric examination in accordance to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, is performed (e.g., acceptance standards, extend and frequency of examination). Specified bolting material properties (e.g., design and procurement specifications, fabrication and vendor drawings, material test reports) may be used to determine if the bolting exceeds the threshold to be classified as high-strength.

Indications of aging in ASME pressure retaining bolting will be evaluated in accordance with Section XI of the ASME Code. Non-ASME Code inspections will follow acceptance criteria established in plant procedures and specifications. Leaking joints do not meet acceptance criteria.

19.2.2.10 Steam Generators

The PSL Steam Generators AMP, previously the PSL Steam Generator Integrity Program (SGIP), 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 AMP is modeled after NEI 97-06, “Steam Generator Program Guidelines” and the referenced EPRI Guidelines of NEI 97-06.

The establishment of a steam generator program for ensuring steam generator tube integrity is required by the PSL 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.

Volumetric inspections are performed on steam generator tubes to identify degradation such as PWSCC, outer diameter stress corrosion cracking (ODSCC), and loss of material (mechanical wear) 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.

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.

19.2.2.11 Open-Cycle Cooling Water System

The PSL Open-Cycle Cooling Water System AMP is an existing AMP, previously part of the Intake Cooling Water System Inspection Program and the Periodic Surveillance and Preventive Maintenance (PSPM) Program, that manages aging effects caused by exposure of internal surfaces of piping, piping components, valves, piping elements, and CCW heat exchangers to a raw water environment from the intake cooling water (ICW) system. The PSL 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 surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling, as well as routine inspection and maintenance, so that corrosion, erosion, protective coating failure, fouling, and biofouling cannot degrade the performance of systems serviced by the ICW system. A one-time CCW heat exchanger performance test was performed to confirm that the CCW heat exchanger tube cleaning frequency was sufficient to maintain the fouling (and resulting heat transfer capability) assumed in the design calculations. When ICW system temperature or pressure differential readings exceed a specified level, then on-demand ICW system testing is performed to verify operability of the system. Inspection methods primarily include visual inspection and eddy current testing (ECT), but also include ultrasonic testing (UT) as needed. This AMP also includes enhancements to the guidance in NRC GL 89-13 that address OE such that aging effects are adequately managed.

19.2.2.12 Closed Treated Water Systems

The PSL Closed Treated Water Systems AMP, previously known as the Chemistry Control Program – Closed-Cycle Cooling Water System Subprogram, 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 PSL Closed Treated Water Systems AMP uses EPRI TR-3002000590, Revision 2, “Closed Cooling Water Chemistry Guideline” per NUREG-2191, XI.M21A as modified by SLR-ISG -2021-02-Mechanical, Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance. PSL will continue to implement monitoring and control guidance updates from industry guidelines in accordance with NEI 03-08.

19.2.2.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is an existing AMP that is currently implemented as part of the PSL Structures Monitoring Program. The PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP was evaluated as a portion of the PSL Structures Monitoring AMP in the initial license renewal application. The PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is evaluated separately in the subsequent license renewal application 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).”

19.2.2.14 Compressed Air Monitoring

The PSL Compressed Air Monitoring AMP is an existing AMP 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 PSL Compressed Air Monitoring AMP:

- Instrument Air sub-system of the Compressed Air System
- Diesel Air Start sub-system of the Emergency Diesel Generator System

The PSL Compressed Air Monitoring AMP also manages components which supply IA to the containment isolation system, ventilation system, feedwater system, chemical and volume control, and main steam system. No portion of the miscellaneous bulk gas systems is required to be included in the scope of the PSL Compressed Air Monitoring AMP.

The PSL Compressed Air Monitoring AMP manages the aging effect of loss of material due to corrosion in compressed air system components located downstream of system air dryers. Aging effects associated with components located upstream of the air dryers, or those exposed to an air environment that is not subject to the preventive or periodic actions of the PSL Compressed Air Monitoring AMP, will be managed by the PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.

The PSL Compressed Air Monitoring AMP includes monitoring of water (moisture), and other contaminants (particulate size and hydrocarbon content) as a preventive measure to keep compressed air quality within specified limits.

The PSL Compressed Air Monitoring AMP is based on the relevant aspects of the PSL response to NRC GL 88-14 and INPO SOER 88-01. The PSL Compressed Air Monitoring AMP incorporates the guidance from the most current ANSI/ISA standards, and will incorporate the guidance from ASME OM-2012, Division 2, Part 28, and EPRI TR-10847 for testing and monitoring of 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.

19.2.2.15 Fire Protection

The PSL Fire Protection AMP is an existing AMP, formerly a portion of the PSL Fire Protection Program. This AMP manages aging effects (loss of material, cracking, and loss of seal) associated with fire barriers. The PSL 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, as well as periodic visual inspection and functional tests of fire-rated doors so that their operability is maintained. The PSL Fire Protection AMP also requires periodic visual inspection of other passive fire protection features credited for the Fire Protection Program like oil collection curbs. The PSL Fire Protection AMP includes periodic inspection and testing of the halon fire suppression systems. UFSAR Section 9.5.1 provides for additional information on the PSL Fire Protection Program.

With respect to preventive actions, PSL 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, delamination, separation, 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, cracking, or elastomer degradation as applicable on fire damper assemblies;

d) No visual indications of missing parts, holes, and wear; and

e) No conditions in the functional tests of fire doors (i.e., the door swings easily, freely, and achieves positive latching).

Visual inspection of at least 10 percent of each type of sealed penetration is performed at a frequency in accordance with the plant's NRC-approved fire protection program or at least once every refueling outage. Visual inspections of fire-rated structures (fire barrier walls, ceilings, and floors), combustible liquid spill retaining features (oil collection curbs), fire-rated assemblies, and fire damper assemblies are conducted at a frequency in accordance with the plant's NRC-approved fire protection program. Periodic visual inspections are performed and functional tests are conducted on fire doors and their closing mechanisms and latches are verified functional in accordance with the plant's NRC-approved fire protection program.

The results of inspections and functional testing of the in-scope fire protection equipment are collected and analyzed, and unacceptable results are documented in the corrective action program. When performance degrades to unacceptable levels, the PSL corrective action program is utilized to drive improvement. During the inspection of penetration seals, if any sign of abnormal degradation is detected within the sample, the inspection sample size is expanded, in accordance with the approved PSL fire protection program, to include an additional 10 percent of each type of sealed penetration.

19.2.2.16 <u>Fire Water System</u>

The PSL Fire Water System AMP is an existing AMP, formerly part of the PSL Fire Protection Program. This AMP manages aging effects associated with water-based fire protection system components. This AMP manages loss of material, wall thinning, cracking, and flow blockage due to fouling by performing periodic visual inspections, tests, and flushes in accordance with the 2011 Edition of NFPA 25.

Testing or replacement of fast-response and traditional sprinkler heads that have been in service for 20 or 50 years, respectively, is performed in accordance with NFPA 25. In addition to NFPA codes and standards, portions of the water-based fire protection system that are: (1) normally dry but periodically subjected to flow and (2) 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 functions. 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 organic or inorganic material sufficient enough 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.

19.2.2.17 Outdoor and Large Atmospheric Metallic Storage Tanks

The PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP is an existing AMP, previously part of the PSPM Program and Structures Monitoring 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 Unit 2 and Common Unit tanks included within the scope of this AMP are as follows:

- Unit 2 Refueling Water Tank (U2 RWT)
- Unit 2 Primary Water Storage Tank (U2 PWST)
- Unit 2 Condensate Storage Tank (U2 CST)

This AMP includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice. Sealant or caulking is used for outdoor tanks at the tank bottom interface. This AMP manages loss of material and cracking by conducting one-time and periodic internal and external visual and surface examinations. Inspections of caulking or sealant are supplemented with physical manipulation. Surface exams are conducted to detect cracking for the stainless steel U2 RWT. Thickness measurements of tank bottoms are conducted to detect degradation (e.g., loss of material on the inaccessible external surface). 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.

19.2.2.18 Fuel Oil Chemistry

The PSL Fuel Oil Chemistry AMP is an existing AMP, previously known as the Chemistry Control Program – Fuel Oil Chemistry Subprogram, 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 (b) measures to verify the effectiveness of the mitigative actions and confirm the insignificance of an aging effect. This AMP includes periodic draining of accumulated water through tank bottom drains; periodic draining, cleaning, and internal visual inspection of the DOSTs, and periodic draining, cleaning, and (to the extent practical) internal inspection of the day tanks. Volumetric examinations are used to assess identified degradation and to monitor for wall loss on internal surfaces of the day tanks.

Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the PSL Technical Specifications. Guidelines of American Society of Testing Materials (ASTM) Standards including ASTM D975 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 PSL One-Time Inspection AMP.

19.2.2.19 Reactor Vessel Material Surveillance

The PSL Reactor Vessel Material Surveillance AMP is an existing AMP formerly a portion of the PSL Reactor Vessel Integrity Program. This AMP includes withdrawal and testing of the surveillance capsule located at 277°, identified in UFSAR Table 5.3-9. This capsule will receive between one to two times the peak reactor vessel neutron fluence of interest at the end of the SPEO used in the TLAAs for upper-shelf energy (USE), PTS, and pressure-temperature (P-T) temperature limits. The surveillance program 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. 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 PSL Reactor Vessel Material Surveillance AMP is to monitor the changes in fracture toughness to the ferritic reactor vessel beltline and extended beltline materials. As described in RIS 2014-11, beltline and extended 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.

This AMP 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.

The objective of the PSL 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 PSL Neutron Fluence Monitoring AMP.

This is a condition monitoring AMP 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 PSL Reactor Vessel Material Surveillance program is also used in conjunction with the PSL 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. With lead factors of less than 1, there is no need to remove a capsule for later reinsertion.

19.2.2.20 <u>One-Time Inspection</u>

The PSL One-Time Inspection AMP is a new condition monitoring 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 subsequent period of extended operation; (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 PSL 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 PSL One-Time Inspection AMP is used to verify the effectiveness of the PSL Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis AMPs. For carbon steel components exposed to water environments that do not include corrosion inhibitors as a preventive action (e.g., raw water and waste water) or carbon steel components that do not have wall thickness measurement examinations conducted of a representative sample of each environment between the 50^{th} and 60^{th} year of operation, 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), and structural integrity].

Periodic inspections are used instead of the PSL One-Time Inspection AMP 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.

19.2.2.21 Selective Leaching

The PSL 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% Zn or greater than 8% Al in susceptible environments. One-time inspections for components exposed to a closed-cycle cooling water or treated water environment will be conducted, based on PSL plant-specific OE which has not revealed selective leaching in these environments. Opportunistic and periodic inspections will be conducted for selective leaching susceptible components exposed to raw water, waste water, soil, and groundwater environments. Opportunistic inspections will be performed whenever components are opened, or whenever buried or submerged surfaces are exposed. The periodic inspections are conducted at an interval of no greater than every 10 years during the SPEO. 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 Unit 2 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 Unit 2. For each population with less than 35 susceptible components, one destructive examination will be performed in each 10-year inspection interval at Unit 2. Where the sample size is not based on the percentage of the population and the inspections will be conducted periodically (not one-time inspections), a reduction in the total number of inspections is acceptable as follows. Eight visual and mechanical inspections (reduced from 10 visual and mechanical inspections) and two destructive examinations will be conducted at Unit 2. If there are less than 35 susceptible components in a sample population at each unit, then one destructive examination will be performed for that sample population at Unit 2.

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.

19.2.2.22 ASME Code Class 1 Small-Bore Piping

The PSL 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 a nominal pipe size (NPS) diameter less than 4-inches and greater than or equal to 1-inch. This AMP provides a one-time volumetric and/or destructive examination of a sample of this Class 1 piping and includes full penetration (butt) and partial penetration (socket) welds. The PSL 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 are performed to determine whether cracking is occurring in the total population of ASME Code Class 1 small-bore piping in the plant. Per NUREG-2191, Table XI.M35-1, PSL Unit 2 is a Category A plant because it has no history of age-related cracking. 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 non-destructive 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 of this ASME Code Class 1 Small-Bore Piping 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 will be implemented.

19.2.2.23 External Surfaces Monitoring of Mechanical Components

The PSL External Surfaces Monitoring of Mechanical Components AMP is an existing AMP that was formerly the PSL Systems and Structures Monitoring Program.

The PSL External Surfaces Monitoring of Mechanical Components AMP is a condition monitoring AMP that manages loss of material, cracking, hardening or loss of strength (of elastomeric and polymeric components), reduction of heat transfer due to fouling (air to fluid heat exchangers), and blistering. The PSL 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 of metallic, polymeric, and elastomer components 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 susceptible stainless steel, copper alloy, and aluminum components. Periodic visual inspections or surface examinations are conducted to manage cracking in metallic components every 10 years during the SPEO. Component surfaces that are insulated and may be exposed to condensation and insulated outdoor components are inspected every at least every 10 years or more frequently as required by plant specific OE. Surfaces that are not readily visible during plant operations and refueling outages are inspected opportunistically when made accessible or within an interval that would provide reasonable assurance that the components’ intended functions are maintained. Other inspections are performed at a frequency not to exceed one refueling cycle.

For certain materials, such as flexible polymers and elastomers, 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 PSL External Surfaces Monitoring of Mechanical Components AMP. 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.

19.2.2.24 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new AMP that manages loss of material, cracking, blistering, wall thinning, reduction of heat transfer due to fouling, flow blockage, and hardening or loss of strength of polymeric materials. Applicable environments will include air, diesel exhaust, raw water, treated water, waste water, fuel oil, and lubricating oil. Some inspections and activities within the scope of the new AMP were previously performed by the PSL 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 and loss of material of stainless steel, copper alloy (>15% Zn), and aluminum components. Aging effects associated with items (except for elastomers) within the scope of the PSL Open-Cycle Cooling Water AMP, the PSL Closed Treated Water Systems AMP, and the PSL Fire Water System AMP are not managed by this AMP.

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 25 components per unit will be inspected for applicable aging effects. Where the sample size will not be based on the percentage of the population, a reduction in the total number of inspections to 19 components inspected per unit is acceptable for the following material and environment combinations because site operating experience has not indicated a difference in aging effects between the two units for the environments listed:

- Air – indoor uncontrolled environment and aluminum, carbon steel, stainless steel, carbon steel with stainless steel internal cladding, cast iron, nickel alloy, and elastomer materials;

- Air – outdoor environment and aluminum, carbon steel, galvanized steel, and stainless steel materials;

- Raw water environment for systems supplied by the same raw water supply (i.e., ICW systems and fire protection systems) and carbon steel, copper alloy, galvanized steel, and stainless steel.

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 procedure will be used.

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.

19.2.2.25 Lubricating Oil Analysis

The PSL Lubricating Oil Analysis AMP is an existing AMP, previously performed as part of PSL'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 PSL Lubricating Oil Analysis AMP maintains lubricating 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.

There are no components utilizing hydraulic oil in the scope of the PSL Lubricating Oil Analysis AMP.

The effectiveness of the PSL Lubricating Oil Analysis AMP will be validated by the results of inspections completed under the PSL One-Time Inspection AMP.

19.2.2.26 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

The PSL Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP, formerly the PSL Metamic® Insert Surveillance Program, is an existing condition monitoring AMP that is implemented to provide reasonable assurance that degradation of the neutron-absorbing material used in spent fuel pools, that could compromise the criticality analysis, will be detected. This AMP relies on periodic inspection, testing, monitoring, and analysis of the criticality design to provide reasonable assurance that the required 5 percent subcriticality margin is maintained during the SPEO. This AMP consists of inspecting the physical condition of the neutron-absorbing material, such as visual appearance, dimensional measurements, weight, geometric changes (e.g., formation of blisters, pits, and bulges), and boron areal density as observed from coupons or in situ. This AMP addresses the aging management of the PSL spent fuel pools' credited neutron-absorbing materials, which include Metamic® inserts and Boral® panels.

19.2.2.27 Buried and Underground Piping and Tanks

The PSL Buried and Underground Piping and Tanks AMP is a new AMP. This is a condition monitoring AMP that manages the aging effects associated with the external surfaces of buried and underground piping.

There are no buried or underground tanks at PSL.

This AMP manages the external surface condition of buried and underground piping for loss of material and cracking for the external surfaces of buried piping fabricated of steel (cast iron, carbon steel, ductile iron) and stainless steel through preventive measures (e.g., coatings, backfill, and compaction), mitigative measures (e.g., electrical isolation between piping and supports of dissimilar metals, etc.), and periodic inspection activities (e.g., direct visual inspection of external surfaces, protective coatings, wrappings and quality of backfill) during opportunistic or directed excavations. The number of inspections is based on the effectiveness of the preventive and mitigative actions.

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. Direct visual inspections are performed on the external surfaces, protective coatings, wrappings, quality of backfill and wall thickness measurements using NDE techniques. Additional inspections are performed on steel piping in lieu of fire main testing.

The table below provides additional information related to inspections. Preventive Action Category F has been selected for monitoring steel piping during the initial monitoring period since the proposed cathodic protection system will not be operational during that time period. Upon entering the SPEO, Preventive Action Category C has been selected for buried steel piping after the cathodic protection system has been in service for approximately 10 years and annual effectiveness reviews are performed. However, if these conditions were to change, the Preventive Action Category would require reevaluation and could potentially change.

The number of inspections for each 10-year inspection period, commencing 10 years prior to the start of SPEO, are based on the inspection quantities noted in NUREG-2191, Table XI.M41-2, adjusted for a 2-Unit plant site.

Material	No. of Inspections	Notes
Steel (buried)	11* prior to the SPEO (Category F) 4 in each 10-year period during the SPEO (Category C)	Includes 2 additional inspections to meet the requirements of NUREG-2191 Section XI.M41, paragraph 4.e.i regarding the aging effects associated with fire mains.
Steel (underground)	3	
Stainless steel (buried)	2	

*If after five years of operation the cathodic protection system does not meet the effectiveness acceptance criteria defined by NUREG-2191, Tables XI.M41-2 and -3 (-850 mV relative to a copper/copper sulfate reference electrode (CSE), instant off, for at least 80 percent of the time, and in operation for at least 85 percent of the time), FPL commits to performing two additional buried steel piping inspections beyond the number required by Preventive Action Category F resulting in a total of thirteen (13) inspections being completed six months prior to the SPEO.

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.

19.2.2.28 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP that will manage degradation of internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, fuel oil, and air 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. Portions of the program were previously part of the Intake Cooling Water System Inspection Program and the Periodic Surveillance and Preventive Maintenance (PSPM) Program. The PSL Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will not be used to manage loss of coating integrity for external coatings. The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will perform inspections of coatings/linings applied to components that will also be managed by the PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP, the PSL Open-Cycle Cooling Water AMP, PSL Closed Treated Water Systems AMP, PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP, PSL Fuel Oil Chemistry AMP, and the PSL Fire Water System AMP.

The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will manage 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 will be performed, where physically possible, in conjunction with the visual inspection.

For tanks and heat exchangers, all accessible surfaces will be inspected. Piping inspections will be sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings will be 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 will not be acceptable. Blisters will be evaluated by a coatings specialist to confirm the surrounding material is sound and the blister size and frequency is not increasing. Minor cracks in cementitious coatings will be acceptable provided there is no evidence of debonding. All other degraded conditions will be evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing will be performed where possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining. Additional inspections will be 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.

19.2.2.29 <u>ASME Section XI, Subsection IWE</u>

The PSL ASME Section XI, Subsection IWE AMP is an existing AMP that was previously part of the ASME Section XI, Subsection IWE Inservice Inspection Program. Inspections identify degradation of pressure-retaining components and their integral attachments to the Class MC steel containment. This condition monitoring AMP provides for inspection and examination of containment surfaces, pressure-retaining welds, seals, gaskets and moisture barriers, pressure-retaining bolting, and pressure-retaining components in accordance with the requirements of ASME Section XI, Subsection IWE, and consistent with 10 CFR 50.55a, “Codes and Standards,” with supplemental recommendations.

The AMP includes periodic visual, surface, and volumetric examinations, where applicable, for signs of degradation, damage, irregularities, and for coated areas distress of the underlying metal shell, and corrective actions. Acceptability of inaccessible areas of steel containment vessel is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas.

In addition, the AMP includes supplemental surface examination to detect cracking for non-piping penetrations (hatches, electrical penetrations, etc.) subject to cyclic loading that have no CLB fatigue analysis. If triggered by plant-specific OE, the AMP includes a one-time supplemental volumetric examination by sampling randomly-selected as well as focused locations susceptible to loss of thickness due to corrosion of the containment vessel that is inaccessible from one side. Inspection results are compared with prior recorded results in acceptance of components for continued service.

19.2.2.30 <u>ASME Section XI, Subsection IWF</u>

The PSL ASME Section XI, Subsection IWF AMP is an existing AMP that was previously known as the ASME Section XI, Subsection IWF Inservice Inspection program. Inspections identify and correct degradation of ASME Class 1, 2, and 3 component supports. This condition monitoring AMP provides for inspection and examination of accessible surface areas of the component supports in accordance with the requirements of ASME Section XI, Subsection IWF.

This AMP consists of periodic visual examination of piping and component supports for signs of degradation, evaluation, and corrective actions. This AMP recommends additional inspections beyond the inspections required by ASME Code Section XI, Subsection IWF. This consists of a one-time inspection of an additional 5 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 subsequent period of extended operation. For high-strength bolting in sizes greater than 1-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.

19.2.2.31 10 CFR Part 50, Appendix J

The PSL 10 CFR Part 50, Appendix J AMP is an existing AMP that was previously part of the ASME Section XI, Subsection IWE Inservice Inspection AMP. The PSL 10 CFR Part 50, Appendix J AMP is a performance monitoring AMP that monitors leakage rates through the containment, including the containment vessel, 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 AMP is implemented in accordance with 10 CFR Part 50, Appendix J and NEI 94-01 Revision 2-A and is subject to the requirements of 10 CFR Part 54. 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 performance of the containment system.

19.2.2.32 Masonry Walls

The PSL Masonry Walls AMP is an existing AMP that was previously implemented as part of the PSL Structures Monitoring Program. The PSL Masonry Walls AMP is evaluated separately in the SLRA and 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 AMP.

19.2.2.33 Structures Monitoring

The PSL Structures Monitoring AMP is an existing AMP that consists of periodic inspection and monitoring of the condition of concrete and steel structures, structural components, components 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 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. Due to aggressive groundwater chemistry (Chlorides > 500 parts per million), the AMP will be enhanced prior to the SPEO to include site-specific evaluations, destructive testing, if warranted, and/or focused inspections of representative accessible (leading indicator) or below-grade inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed 5 years.

19.2.2.34 Inspection of Water-Control Structures Associated with Nuclear Power Plants

The PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is an existing AMP that is currently implemented as part of the PSL Structures Monitoring Program. The PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP was evaluated as a portion of the PSL Systems and Structures Monitoring AMP in the initial license renewal application. The PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is evaluated separately in the subsequent license renewal application 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 PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP consists of inspection and surveillance of control structures for raw water. The structures within the scope of the PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP include the ICW canal (the portion between the emergency cooling canal and the intake structure), emergency cooling canal, Unit 2 intake structure, and ultimate heat sink dam. The AMP 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 PSL Structures Monitoring AMP.

19.2.2.35 Protective Coating Monitoring and Maintenance

The PSL Protective Coating Monitoring and Maintenance AMP is an existing AMP that was not previously credited for License Renewal. The PSL Protective Coating Monitoring and Maintenance AMP ensures monitoring and maintenance of Service Level I coatings is implemented in accordance with Position C4 of RG 1.54, Revision 3, for the subsequent period of extended operation. The AMP consists of guidance for selection, application, inspection, and maintenance of protective coatings. The AMP will use the aging management detection methods, inspector qualifications, inspection frequency, monitoring and trending, and acceptance criteria defined in ASTM D5163-08, "Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants." The AMP 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).

19.2.2.36 <u>Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements</u>

The PSL 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 insulation material within the scope of SLR subjected to adverse localized environments (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 plant-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 electrical cable and connection insulation. A sample population of electrical cable and connection insulation is utilized if testing is performed. If testing is deemed necessary, a sample of 20 percent of each electrical cable and connection insulation 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 being subjected to an adverse localized environment are evaluated for cumulative aging effects during the SPEO.

19.2.2.37 <u>Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits</u>

The PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP is a new AMP. Portions of this AMP were previously part of the Containment Cable Inspection Program. This AMP will manage the aging effects of the applicable cables and connections in the following systems/components:

- Nuclear Instrumentation: Excore Source, Intermediate, and Power Range Channels
- Control Room Air Intake Radiation Monitors

The purpose of this new 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 functions 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 to be completed no later than 6 months prior to the SPEO and at least once every 10 years thereafter.

19.2.2.38 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PSL Electrical Insulation for Inaccessible Medium-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 medium-voltage 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 is minimized due to effective automatic or passive drainage is not considered significant moisture for this AMP.

In-scope inaccessible medium-voltage power cables exposed to significant moisture will be 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-related degradation of the cable insulation. The first tests for subsequent 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 operating experience. The medium-voltage wetted cables at PSL are lead-sheathed, and therefore, will receive a one-time test prior to the SPEO. The results of this test will dictate any further actions.

This will be a condition monitoring AMP. However, this AMP will include periodic actions to prevent inaccessible medium-voltage power cables from being exposed to significant moisture. Periodic actions to mitigate inaccessible medium-voltage power cable exposure to significant moisture will include inspection for water accumulation in cable manholes and conduits, and removing water, as needed. Inspections will be performed periodically based on water accumulation over time. The periodic inspection will occur 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. The periodic inspection will include documentation of the effectiveness of either automatic or passive drainage systems, or manual pumping of manholes or vaults, in preventing inaccessible medium-voltage power cable exposure to significant moisture.

Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent removal of accumulated water by sump pumps prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or the control room. Reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

19.2.2.39 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PSL 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 that are within the scope of SLR and potentially 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 is a condition monitoring AMP. However, this AMP also 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-related 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.

Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent removal of accumulated water by sump pump prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or the control room. Reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

19.2.2.40 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PSL 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 current licensing basis 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) low-voltage power cables, including those designed for continuous wetting or submergence, within the scope of SLR potentially 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.

Periodic actions to mitigate inaccessible low-voltage power cable exposure to significant moisture include inspections 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 prior to the SPEO. Inspections are also performed after event-driven occurrences, such as heavy rain or flooding. Inspection frequencies are adjusted based on inspection results including plant-specific OE.

Performing periodic visual inspections of low-voltage power cables accessible from manholes, vaults, or other underground raceways for jacket surface abnormalities. The visual inspections of low-voltage power cables occur at least once every 6 years and may be coordinated with the periodic inspections for water accumulation. Inaccessible and underground low-voltage power cables found to be exposed to significant moisture are evaluated to determine whether testing is required. Initial testing is performed once on a sample population to determine the condition of the electrical insulation. One or more tests may be required based on cable type, application, and electrical insulation material to determine the age-related degradation of the cable insulation. Inaccessible low-voltage power cables designed for continuous wetting or submergence are also included in this AMP. The need for additional periodic tests and inspections is determined by the test / inspection results as well as industry and plant-specific OE.

Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent removal of accumulated water by sump pumps prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or the control room. Reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

19.2.2.41 Metal Enclosed Bus

The PSL Metal Enclosed Bus AMP is a new AMP. Portions of this AMP were previously part of the Periodic Surveillance and Preventive Maintenance (PSPM) Program. 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 is a condition monitoring AMP. 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). The PSL Structures Monitoring AMP manages the aging effects on external metal enclosed bus (MEB) surfaces and structural supports. The first inspections 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 bar connections caused by repeated thermal cycling of connected loads by using low resistance testing using a micro-ohmmeter. A sample of 20 percent with a maximum sample of 25 constitutes a representative bolted bus connection sample size. In addition to 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 measuring connection resistance of bolted connections, for accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., PSL 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.

19.2.2.42 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The PSL Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP. The purpose of the 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 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 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, will 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 AMP 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 AMP.

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.

19.2.2.43 High-Voltage Insulators

The PSL High-Voltage Insulators AMP is a new AMP. The purpose of the 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 PSL High-Voltage Insulator AMP was developed specifically to age manage high-voltage insulators (used on systems with nominal operating voltages greater than 1 kV and equal to or less than 765 kV) susceptible to aging degradation due to local environmental conditions. This AMP is applicable to different types of high-voltage insulators such as porcelain, toughened glass, and polymer.

This is a condition monitoring AMP that manages loss of material and 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 AMP 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 provides 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, polymer, 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, peeling of silicone rubber sleeves for polymer insulators, or degradation of glazing on porcelain insulators. Visual inspections may be supplemented with infrared thermography inspections to detect high-voltage insulator reduced insulation resistance. Corona cameras may also be employed to detect early signs of corona emissions.

The high-voltage insulators within the scope of this program are to be visually inspected at a frequency based on plant-specific OE with the specific type of insulator used (i.e., porcelain, polymer, toughened glass). The first inspections for SLR are to be completed prior to the SPEO.

19.2.2.44 Pressurizer Surge Line

The PSL Pressurizer Surge Line AMP, previously known as the Pressurizer Surge Line Inspection Program (Fatigue), is an existing AMP that was originally developed to address the effects of environmentally assisted fatigue (EAF) for the PSL pressurizer surge line welds during the initial period of extended operation (PEO).

The approach to address reactor water environmental effects of fatigue on the PSL Unit 2 pressurizer surge line accomplishes two objectives. First, the TLAA on fatigue design has been resolved by confirming that the original transient design limits remain valid for the 80-year operating period. Confirmation by fatigue monitoring will ensure that these transient design limits are not exceeded. Second, reactor water environmental effects on fatigue life are examined using the most recent data from laboratory simulation of the reactor coolant environment. To address the initial 40-year operating period, Idaho National Engineering Laboratories evaluated fatigue-sensitive component locations in plants designed by all four U.S. nuclear steam supply system (NSSS) vendors, as reported in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," March 1995. This evaluation included calculation of fatigue usage factors for critical fatigue sensitive component locations of older vintage Combustion Engineering PWRs which match PSL relatively closely with respect to design codes used, as well as the analytical approach and techniques used. In addition, the design cycles considered in the evaluation match or bound the PSL Unit 2 design. Fatigue monitoring is performed to provide reasonable assurance that these limits are not exceeded. In this manner, the original transient design limits for fatigue are confirmed to remain valid for the current 40-year operating period, the initial 20-year PEO, and the 20-year SPEO of PSL Unit 2.

The PSL Unit 2 pressurizer surge line EAF analysis has been revised for the 80-year SPEO using the methodology outlined in NUREG/CR-6909, Revision 1, “Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, Final Report” for stainless steels, carbon and low-alloys steels, and Ni-Cr-Fe alloys. The results of the analysis confirms that the Pressurizer Surge Line AMP is appropriate for managing aging of the PSL Unit 2 pressurizer surge line during the SPEO.

The PSL Unit 2 surge line welds have previously been examined ultrasonically during the first three in-service inspection intervals in accordance with the requirements of ASME Section XI, Subsection IWB. All in scope welds in the PSL Unit 2 pressurizer surge line were examined during the ISI 4th Interval of PSL Unit 2 in 2017. The results of these inspections were utilized to assess fatigue of the surge lines. In addition to these inspections, EAF of the surge lines welds is addressed using the following approach:

(1) FPL elected to manage the effects of EAF of the pressurizer surge line welds by an aging management inspection program approved by the NRC.

(2) The aging management of the surge line is accomplished by a combination of flaw tolerance analysis as per ASME Section XI (applicable Edition and Addenda as referenced in the Unit 2 ISI Program Plan), Appendix L and inspection under the PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP. The aging effect managed with these inspections is cracking due to EAF. The technical justification and inspection frequency are supported by the flaw tolerance analysis based on the methodology noted in ASME Section XI, Nonmandatory Appendix L, "Operating Plant Fatigue Assessment." Based on postulated flaw tolerance analysis, and using the guidelines of ASME Code Section XI, Appendix L, Table L-3420-1, the periodic inspection schedule is determined to be 10 years.

(3) All in scope pressurizer surge line welds are examined in accordance with ASME Section XI, IWB for Class 1 welds, as modified by the requirements of 10 CFR 50.55a. Inservice examinations for the surge line welds include volumetric examinations. In each 10-year ISI interval during the SPEO, all in scope surge line welds are inspected in accordance with the PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD AMP under Augmented programs within the ISI Program Plans. Note that welds with structural weld overlays (SWOL) have been screened out from the scope of

analysis and inspections. The SWOL welds are inspected under ISI AMP requirements.

19.3 Time-Limited Aging Analyses

With respect to plant TLAA, 10 CFR 54.21(c) requires 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 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 TLAA, as defined in 10 CFR 54.3, are listed in Section 19.3.2 through, and including, Section 19.3.6.7 and are evaluated per the requirements of 10 CFR 54.21(c).

19.3.1 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 exemptions were based on TLAA. Based on this review, there is currently one active 10 CFR 50.12 exemption request for PSL Unit 2 that relates to a time sensitive TLAA topic. This TLAA-related exemption requests an exemption from the requirements of 10 CFR 50, Appendix G, to use the methodology of Topical Report CE NPSD-683-A, Rev 06, "Development of a RCS Pressure and Temperature Limits Report for the Removal of P-T Limits and LTOP Requirements from the Technical Specifications," for the generation of the current P-T limits for the PSL Unit 2 reactor coolant pressure boundary during normal operating and hydrostatic or leak rate testing conditions. Specifically, use of the topical report methodology requires an exemption from the requirements of 10 CFR Part 50, Appendix G, Section IV.A.2, "Pressure-Temperature Limits and Minimum Temperature Requirements." This exemption was approved by the NRC in letter dated April 30, 2012 (Reference ML12096A270). The evaluation of this TLAA-related exemption for the 80-year SPEO is included in UFSAR Section 19.3.2.5.

19.3.2 Reactor Vessel Neutron Embrittlement

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, 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 PSL Reactor Vessel Material Surveillance AMP is described in Section 19.2.2.19.

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 TLAA concerns the effect of IE on the beltline and extended beltline regions of the PSL Unit 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 TLAA, as defined in 10 CFR 54.21(c). Therefore, the following TLAA were evaluated for the increased neutron fluence associated with 80 years of operations:

- Neutron fluence projections (Section 19.3.2.1)
- Pressurized thermal shock (PTS) (Section 19.3.2.2)
- Upper-shelf energy (USE) (Section 19.3.2.3)
- Adjusted reference temperature (Section 19.3.2.4)
- Pressure-temperature limits and low temperature overpressure protection (LTOP) setpoints (Section 19.3.2.5)

19.3.2.1 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. These fluence projections 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. The projected 80-year EFPY for PSL Unit 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 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 1.0×10^{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 PSL Neutron Fluence Monitoring AMP and the PSL Reactor Vessel Material Surveillance AMP ensure the continued validity and adequacy of projected neutron fluence analyses and related neutron fluence-based TLAAs as described in Section 19.2.1.2 and 19.2.2.19, respectively.

19.3.2.2 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, provides protection against PTS events. It establishes screening criteria on PWR vessel embrittlement, as measured by the maximum reference nil-ductility transition temperature in the limiting beltline component at the end of license, termed RT_{PTS}. RT_{PTS} screening values are set for beltline axial welds, forgings or plates, and for beltline circumferential weld seams for plant operation to the end-of-plant license. Calculating the reference temperature for pressurized thermal shock (RT_{PTS}) values is consistent with the methods given in Regulatory Guide 1.99.

The current PTS analysis, evaluated for 60 years of operation is a TLAA requiring evaluation for the 80-year SPEO since a change in the operating license term of the facility is being requested. The accepted methods of 10 CFR 50.61 were used with the maximum fluence values to calculate the RT_{PTS} values for the RPV materials at 72 EFPY. The limiting RT_{PTS} value for the PSL Unit 2 RPV base metal or longitudinal weld materials at 72 EFPY is 195.3°F, which corresponds to intermediate shell plate M-605-1 with credible surveillance data. The limiting RT_{PTS} value for circumferentially-oriented weld materials at 72 EFPY is 64.1°F, which corresponds to the intermediate to lower shell girth weld seam 101-171 (Heat #'s 83637 / 3P7317). All of the beltline reactor vessel materials have been projected to remain below the 10 CFR 50.61 RT_{PTS} screening criteria values of 270ºF for plates, forgings, and longitudinal welds, and 300ºF for circumferentially-oriented welds.

The PTS analyses have been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

19.3.2.3 Upper-Shelf Energy

Upper-shelf energy (USE) is the parameter used to indicate the toughness of a material at elevated temperature. There are two sets of rules that govern USE acceptance criteria. 10 CFR 50, Appendix G, Paragraph IV.A.1.a, states that RPV 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 ASME Code, Section XI.

The current licensing basis upper-shelf energy (USE) calculations were prepared for the Unit 2 RPV beltline and extended beltline materials for 55 EFPY. Since the USE value is a function of neutron fluence which is associated with a specified operating period, the USE calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for the 80-year SPEO.

There are two methods that can 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. For RPV beltline and extended beltline materials that are not in the surveillance program or have non-credible data, the Charpy USE (Position 1.2) is assumed to decrease as a function of fluence and copper content, as indicated in RG 1.99. When two or more credible surveillance sets become available from the RPV, they may be used to determine the Charpy USE of the surveillance material. The surveillance data are then used in conjunction with RG 1.99 to predict the change in USE (Position 2.2) of the RPV material due to irradiation. Per RG 1.99, when credible data exist, the Position 2.2 projected USE value should be used in preference to the Position 1.2 projected USE value.

The projected USE values were calculated to determine if the Unit 2 beltline and extended beltline materials remain above the 50 ft-lb criterion at 72 EFPY. The limiting PSL Unit 2 projected USE value for SPEO is lower shell plate M-4116-1 with a projected USE of 66.4 ft-lb.

The USE analyses have been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

19.3.2.4 Adjusted Reference Temperature

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 adjusted reference temperature (ART) of the limiting beltline or extended beltline material is used to adjust the beltline pressure-temperature (P-T) limit curves to account for irradiation effects. Regulatory Guide (RG) 1.99 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. 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. Since the ΔRT_{NDT} value is a function neutron fluence, these ART calculations meet the criteria of

10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for the 80-year SPEO.

The limiting 72 EFPY ART values for PSL Unit 2 correspond to the intermediate shell plate M-605-1.

A determination of the applicability of the current end-of-license extension (EOLE) P-T limit curves can be made by comparing the ART values contained in the Unit 2 P-T limits analyses of record with the ART values determined for the SPEO. The results of the comparison conclude that the current PSL Unit 2 P-T limit curves and low temperature overpressure protection (LTOP) enable temperatures remain valid through the projected EOLE.

The PSL Unit 2 ART analyses have been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

19.3.2.5 Pressure-Temperature Limits and Low Temperature Overpressure Protection (LTOP) Setpoints

10 CFR Part 50 Appendix G requires that the reactor pressure vessel (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 PSL Unit 2 heatup and cooldown curves were calculated using the most limiting value of RT_{NDT} corresponding to the limiting material in the beltline and extended beltline regions of the reactor vessel for 55 EFPY. 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, the PSL Unit 2 Technical Specifications specify the power operated relief valve (PORV) and shutdown cooling relief valve lift settings required to mitigate the consequences of low temperature overpressure (LTOP) events. Each time the P-T limit curves are revised, the LTOP PORV and shutdown cooling relief valve lift settings must be reevaluated. Therefore, LTOP protection limits are considered part of the calculation of P-T curves.

The current 55 EFPY P-T limits for PSL Unit 2 requested an exemption from the requirements of 10 CFR 50, Appendix G, to use the methodology of Topical Report CE NPSD-683-A, Rev 06, for the generation of the P-T limits. In accordance with 10 CFR 50.12, the use of this exemptions was approved by the NRC on April 30, 2012. The TLAA evaluation for the SPEO provides justification for continuation of this TLAA-related exemption through 55 EFPY for PSL Unit 2.

The PSL Unit 2 P-T limit curves and LTOP PORV and shutdown cooling relief valve lift settings will be updated (if required) and a Technical Specification change request will be submitted for approval prior to exceeding the current 55 EFPY limit. The PSL Reactor Vessel Material Surveillance AMP (Section 19.2.2.19) will ensure that updated P-T limits and LTOP lift settings based upon updated ART values will be submitted to the NRC for approval, as required, prior to exceeding the current terms of applicability for PSL Unit 2.

Therefore, the P-T limits and LTOP protection TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

19.3.3 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 TLAA for PSL. Specific components have been designed considering transient cycle assumptions, as listed in vendor specifications and the PSL Unit 2 UFSAR. Fatigue analyses are considered TLAA 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 19.3.3.1)
- Metal fatigue of Non-Class 1 components (Section 19.3.3.2)
- Environmentally-assisted fatigue (Section 19.3.3.3)
- High-energy line break analyses (Section 19.3.3.4)

19.3.3.1 Metal Fatigue of Class 1 Components

The ASME Section III, Class 1 Code requires a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded. These 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 factors (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 Class 1 components were assessed for impact on fatigue:

- Reactor vessel
- Control element drive mechanisms
- RCS piping
- Steam generators
- Reactor coolant pumps

- Pressurizer
- Reactor vessel internals

With the exception of the loss of letdown flow transient, the 40-year design cycles (CLB cycles) for these Class 1 components were determined to bound 80 years of plant operations. For the SPEO, the loss of letdown flow transient was increased to 500 cycles. This transient is considered in the fatigue analyses of record (AORs) for the Class 1 cold leg charging nozzles, charging piping, and letdown piping. These analyses have been reconciled for the SPEO using 500 loss of letdown flow cycles. To accomplish this, the detailed fatigue results for the limiting component locations were extracted from the AORs and the component CUF was recalculated considering 500 loss of letdown flow cycles. The results demonstrate that the charging nozzles, charging piping, and letdown piping meet the CUF acceptance criterion assuming 500 loss of letdown flow cycles.

Therefore, the Class 1 component fatigue analyses remain valid for the SPEO. In order to provide reasonable assurance that the design cycles remain bounding in the fatigue analyses, the PSL Fatigue Monitoring AMP (Section 19.2.1.1) will track cycles for significant fatigue transients, including the loss of letdown flow transient, and provide reasonable assurance that corrective action is taken prior to potentially exceeding fatigue design limits. Therefore, the effects of fatigue on the intended function(s) of ASME Section III, Class 1 components will be adequately managed by the PSL Fatigue Monitoring AMP (Section 19.2.1.1) for the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

19.3.3.2 <u>Metal Fatigue of Non-Class 1 Components</u>

The PSL Unit 2 non-Class 1 reactor coolant system (RCS) piping and balance-of-plant piping systems within the scope of subsequent license renewal are designed to the requirements of ASME Section III Class 2, ASME Section III Class 3, and ANSI B31.1 Codes. Piping and components designed in accordance with these Codes 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. These non-Class 1 piping Codes first require 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 ASME Section III Class 2, ASME Section III Class 3, and 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 ASME Section III Class 2, ASME Section III Class 3, and ANSI B31.1 piping systems 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 for all mechanical systems with the exception of the PSL Unit 2 RCS hot leg sample piping.

For the 60-year license renewal PEO, the RCS hot leg sample lines were determined to be limiting as these samples are taken on a daily basis. For the 80-year SPEO, daily hot leg samples would equate to 80 x 365 = 29,200 cycles and exceeds the 7000 thermal cycle limit assuming a stress range reduction factor (f) of 1.0. Therefore, a plant specific analysis was developed for the 80-year SPEO for PSL Unit 2 using a stress range reduction factor (f) of 0.7. Acceptable stress results were obtained with f = 0.7 and justifies a maximum number of cycles at 45,000 for the SPEO. This exceeds the 29,200 thermal cycles assumed for the 80-year SPEO for the PSL Unit 2 RCS hot leg sample line.

Therefore, the ASME Section III Class 2, ASME Section III Class 3, and ANSI B31.1 allowable stress calculations remain valid for the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

19.3.3.3 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 cumulative usage factor (CUF_{en}) 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” 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. Any additional limiting locations are identified through an environmentally-assisted fatigue (EAF) screening evaluation. The EAF screening process evaluates existing CLB fatigue usage values for the ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 equipment and piping components, to determine the lead indicator (also referred to as sentinel) locations for EAF.

Calculations were prepared to document the evaluations of environmentally assisted fatigue for ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 pressure boundary components that are in contact with the reactor coolant and determine CUF_{en} values. The resultant CUF_{en} values for each of the ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 component locations are less than the ASME Code limit of 1.0, with the exception of the pressurizer surge line, and are therefore acceptable. The Fatigue Monitoring AMP (Section 19.2.1.1) 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. In lieu of additional analyses to refine the CUF_{en} for the pressurizer surge line, PSL has selected aging management to address pressurizer surge line fatigue during the SPEO, consistent with what is currently done for the PEO.

Therefore, the effects of EAF on the intended functions of ASME Code, Section III, ANSI B31.7, and NUREG/CR-6260 component locations will be managed by the Fatigue Monitoring AMP (Section 19.2.1.1) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

For the pressurizer surge line, the effects of aging due to environmentally-assisted fatigue will continue to be managed by the Pressurizer Surge Line AMP (Section 19.2.2.4) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

19.3.3.4 High-Energy Line Break Analyses

The PSL Unit 2 HELB analysis methodology is discussed in UFSAR Section 3.6 and indicates the criteria for pipe breaks inside containment has been postulated in accordance with Regulatory Guide 1.46 and pipe breaks outside containment followed the guidance provided in letters sent by A. Giambusso, AEC Directorate of Licensing, in December 1972. The methodology used to define break locations is further described in UFSAR Section 3.6.2 and indicates that both the CUF criterion (CUF > 0.1) and the maximum allowable stress criterion were used to determine break locations. Since both the CUF and maximum allowable stress methods are based on time-dependent fatigue design cycles, HELB break locations are considered TLAAs for PSL Unit 2.

As indicated in UFSAR Section 19.3.3.2, the PSL Unit 2 Class 1 reactor coolant piping was originally designed to the requirements of ASME Boiler and Pressure Vessel Code, Section III, Class 1 piping Code which requires a design analysis for the piping that addresses fatigue and establishes limits such that initiation of fatigue cracks is precluded. These fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients described in the design specifications. As discussed in UFSAR Section 19.3.3.1, the original PSL Unit 2 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Therefore, the fatigue analyses, corresponding CUFs, and postulated Class 1 piping HELB break locations remain valid for the SPEO. Therefore, the PSL Unit 2 ASME Section III, Class 1 fatigue calculations and postulated HELB break locations remain valid for the SPEO. To ensure the Class 1 piping postulated HELB break locations based on CUFs tied to fatigue design cycles remain valid for the SPEO, the Fatigue Monitoring AMP (Section 19.2.1.1) will track cycles for the significant fatigue transients and ensure corrective action is taken prior to potentially exceeding fatigue design limits. Therefore, the TLAA for Class 1 piping is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

UFSAR Section 19.3.3.2 indicates that the PSL Unit 2 non-Class 1 piping systems were originally designed in accordance with the requirements of the ASME Section III Class 2, ASME Section III Class 3, and ANSI B31.1 requirements. The cyclic qualification of the piping per these Codes is based on the number of equivalent full temperature cycles and corresponding stress range reduction factor and are considered implicit fatigue analyses because they are based on the number of fatigue cycles anticipated for the life of the component. UFSAR Section 19.3.3.2 concludes that a conservative number of projected fatigue cycles for 80 years of plant operation for piping systems in the scope of SLR and designed to these Codes will not be exceeded for the 80-year SPEO. Therefore, the implicit fatigue analyses and postulated HELB break locations for PSL Unit 2 also remain valid for the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

19.3.4 Environmental Qualification of Electrical 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 TLAA. 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 Environmental Qualification 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 Environmental Qualification Program that specify a qualification of at least 60 years have been identified as TLAA for license renewal because the criteria contained in 10 CFR 54.3 are met.

The PSL Environmental Qualification of Electric Equipment AMP (Section 19.2.1.3) 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 lives.

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

Division of Operating Reactors (DOR) Guidelines, NUREG-0588, and NRC RG 1.89, Revision 1.

The PSL Environmental Qualification of Electric Equipment AMP (Section 19.2.1.3) will manage the effects of aging or the components associated with the EQ TLAA. This AMP 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 PSL Environmental Qualification of Electric Equipment AMP (Section 19.2.1.3) 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).

19.3.5 Containment Liner Plate, Metal Containments and Penetrations Fatigue

Metal Containment Fatigue

The PSL Unit 2 containment vessel is fabricated from welded ASME-SA 516 Grade 70 steel plates to provide an essentially leak-tight barrier. Design criteria applied to the steel containment vessels assure that the specified leak rate is not exceeded under the design basis accident conditions. The PSL Unit 2 containment vessel is designed in accordance with the 1971 Edition of ASME Boiler and Pressure Vessel Code, Section III. The CLB for the PSL Unit 2 containment vessel includes a fatigue waiver evaluation that precludes the need for a detailed fatigue analysis.

A common evaluation of the PSL Units 1 and 2 containment vessel fatigue waivers was performed for SLR and concluded that the fatigue waivers remain valid through the 80-year SPEO since the service loading of the vessels meet all the following six fatigue waiver conditions of the applicable ASME Codes:

1) Atmospheric to operating pressure cycles
2) Normal service pressure fluctuations
3) Temperature difference - startup and shutdown
4) Temperature difference - normal service
5) Temperature difference - dissimilar materials
6) Mechanical loads

Therefore, the fatigue waiver for the PSL Unit 2 containment vessel remains valid through the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

Penetrations Fatigue

The PSL Unit 2 containment penetrations are specified to withstand a lifetime total of 7000 cycles of expansion and compression due to maximum operating thermal expansion, and 200 cycles of other movements (seismic motion and differential settlement). The PSL Unit 2 containment penetrations are categorized as follows:

1) Type I - those which must accommodate considerable thermal movements (hot penetrations)
2) Type II - those which are not required to accommodate thermal movements (low temperature penetrations)
3) Type III - those which must accommodate moderate thermal movements (semi-hot penetrations)
4) Type IV - containment sump recirculation suction lines
5) Type V - fuel transfer tube

The thermal fatigue design limits of the Type I and Type III containment penetration bellows (7,000 thermal cycles) are bounded by the thermal fatigue design limits of their associated piping systems as discussed in UFSAR Sections 4.3.1 and 4.3.2. The 200 cycles of differential settlement and seismic motion are also bounding for the SPEO since they are not susceptible to any significant differential settlement they have not been subjected to any seismic loading to date.

Type II penetrations are low temperature penetrations, Type IV penetrations are only used during post-accident scenarios, and the Type V penetration is the PSL Unit 2 transfer tube. As such, these penetrations are not exposed to large thermal loads or thermal movements; however, these penetrations were conservatively designed for 7,000 cycles of expansion and compression due to operating thermal expansion and 200 cycles of differential settlement and seismic motion. The 7000 thermal cycles and 200 cycles of differential settlement and seismic motion for Type II, Type IV, and Type V penetrations are bounding for the SPEO.

The analyses associated with the PSL Unit 2 containment penetration fatigue have been evaluated and determined to remain valid for the SPEO, in accordance with 10 CFR 54.21(c)(1)(i).

19.3.6 Other Plant-Specific TLAA

19.3.6.1 Leak-Before-Break of Reactor Coolant System Loop Piping

The Combustion Engineering Owners Group (CEOG) performed the leak-before-break (LBB) evaluation CEN-367-A, for the PSL Units 1 and 2 primary loop piping in February 1991 along with other Combustion Engineering designed nuclear steam supply systems of similar layouts. The LBB evaluation was updated in 2010 for Unit 2 as part of the extended power uprate (EPU) project. In comparing the revised plant-specific loads for the EPU to the evaluation performed in CEN-367-A, the PSL Unit 2 RCS hot and cold leg piping remained qualified for the LBB under EPU conditions and that CEN-367-A remained applicable for PSL Unit 2.

WCAP-18617-P/NP performed the LBB evaluation for PSL Units 1 and 2 assuming an 80-year plant life. The analysis documented the plant-specific geometry, loading, and material properties used in the fracture mechanics evaluation.

The PSL Units 1 and 2 primary loop piping is constructed from carbon steel material with stainless steel cladding. The carbon steel cold leg piping is connected to the RCP suction and discharge nozzles and the nozzle safe-ends contain A351-CF8M CASS material and Alloy 600 dissimilar weld material. The CASS piping material is susceptible to thermal aging embrittlement at the reactor operating temperatures and the Alloy 600 weld material is susceptible to primary water stress corrosion cracking (PWSCC).

Based on NUREG/CR-4513, the fracture toughness correlations used for the full aged condition are applicable for plants operating at ≥ 15 EFPY for the A351-CF8M materials. For the 80-year SPEO, the materials will thermally age. Therefore, the use of the fracture toughness correlations is applicable for the fully aged or saturated condition of the PSL Units 1 and 2 RCP nozzle safe-ends. WCAP-18617-P/NP includes a recalculation of CASS fracture toughness properties based on NUREG/CR-4513 and the LBB analysis results for the CASS safe-end locations are acceptable for the thermal aging effect and for PWSCC. In addition, the fatigue crack growth analysis originally included in CEN-367-A used generic design basis transient cycles that envelope the projected 80-year transient cycles for PSL Units 1 and 2 to calculate the crack growth. Therefore, the generic fatigue crack growth analysis results are representative of the PSL Unit 2 fatigue crack growth and is applicable for the 80-year SPEO.

WCAP-18617-P/NP demonstrates that the conclusions reached in CEN-367-A remain applicable to PSL Unit 2 in accordance with 10 CFR 54.21(c)(1)(ii) and the dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis for the 80-year SPEO.

19.3.6.2 Alloy 600 Instrument Nozzle Repairs

Small bore Alloy 600 nozzles, such as pressurizer and RCS hot leg instrumentation nozzles in Combustion Engineering (CE) designed PWRs have developed leaks or partial through-wall cracks as a result of primary water stress corrosion cracking (PWSCC). The residual stresses imposed by the partial-penetration "J" welds between the nozzles and the low alloy or carbon steel pressure boundary components are the driving force for crack initiation and propagation.

PSL Unit 2 has experienced instances of Alloy 600 instrument nozzle leakage over the design life of the plants. Therefore, repairs have been done to Unit 2 pressurizer and Unit 2 RCS hot leg Alloy 600 instrument nozzles by relocating the partial penetration attachment weld from the interior surface of the component to the outside surface of the component. Preventative repairs were also performed on this population of instrument nozzles to prevent future leakage.

The Alloy 600 instrument nozzle repairs were previously evaluated for the 60-year PEO based on corrosion and fracture mechanics analyses justifying the acceptability of indications in the "J" weld based on a conservative corrosion rate, postulated flaw size, and flaw growth analyses. The repair evaluation was performed based on the fracture mechanics analysis provided in Combustion Engineering Owners Group (CEOG) Topical Report CE NPSD-1198-P and WCAP-15973-P-A and require evaluation for the SPEO.

Westinghouse letter report LTR-SDA-20-097-P/NP reassesses the Alloy 600 instrument nozzle repairs for the PSL Unit 2 SPEO and includes the following topics in accordance with the request in NRC Safety Evaluation (SE) related to WCAP-15973-P (Reference ML050180528):

a) Calculate the maximum bore diameter at the end of 80 years operation considering the carbon and low-alloy steel borated water corrosion to demonstrate that the limiting allowable bore diameters are not exceeded.

b) Reconcile that the fatigue crack growth and flaw stability evaluation in WCAP-15973-P remain valid for the 80 years operation of PSL Unit 2 to demonstrate that the ASME code acceptance criteria for crack growth and crack stability are met for the rest of the plant life including the extended operation.

c) Provide acceptable bases and arguments for concluding that unacceptable growth of the existing flaw by stress corrosion into the vessels or piping is improbable.

Westinghouse report LTR-SDA-20-097-P/NP addressed each of these topics as required by the NRC SE and determined that the conclusions reached in (CEOG) Topical Report CE NPSD-1198-P and WCAP-15973-P-A regarding the PSL Unit 2 Alloy 600 instrument nozzle repairs remain valid through the SPEO.

19.3.6.3 Reactor Coolant Pump Flywheel Fatigue Crack Growth

The RCP flywheels are discussed in Section 5.4.1 of the PSL Unit 2 UFSAR. During normal operation, the RCP 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 RCP increase both the potential for failure and the kinetic energy. The aging effect of concern is fatigue crack initiation in the flywheel.

As discussed in Section 4.1.2 of NUREG-1779, the PSL Unit 2 RCP crack growth calculation was determined not to be a TLAA for the 60-year PEO as a review of the Unit 2 CLB did not identify or reference fatigue crack growth calculations for the flywheels. However, on October 9, 2019, FPL requested an amendment to the Renewed Facility Operating License for PSL Unit 2 to modify the Technical Specifications for the RCP flywheel inspection program requirements to be consistent with the conclusions and limitations specified in NRC safety evaluation (SE) of Topical Report SIR-94-080, Revision 1 “Relaxation of Reactor Coolant Pump Flywheel Inspection Requirements (Reference ML20013C086).

Topical Report SIR-94-080 conservatively assumes 4000 cycles of RCP startups and shutdowns in its analysis of fatigue crack growth rates. The evaluation of the RCP flywheel TLAA for PSL Unit 2 stated that the projected lifetime occurrences of plant heatups and cooldowns is 500 cycles based on the original plant 40-year design life and that the RCPs are cycled when filling and venting the RCS prior to unit start-up.

Conservatively estimating three RCP start/stop cycles per fill and vent activity and a fill and vent activity for each heatup and cooldown results in (500 x 4) or 2000 RCP start/stop cycles the 80-year SPEO, which is well within the 4000 cycles assumed in Topical Report SIR-94-080. This conclusion is based on the fact that the 500 heatup and cooldown cycle limit for the 60-year PEO remain applicable for the PSL Unit 2 80-year SPEO as discussed in Unit 2 UFSAR Section 19.3.3.1.

Therefore, the PSL Unit 2 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).

19.3.6.4 Reactor Coolant Pump Code Case N-481

The PSL Unit 2 RCPs are Byron-Jackson vertical, single bottom suction, horizontal discharge, centrifugal motor-driven pumps. The pump casings are fabricated from ASTM A-351, Grade CF-8M CASS material. In 1993, the Combustion Engineering Owners Group (CEOG) performed ASME Code Case N-481 flaw evaluations for several CE NSSS fleet pumps, including the PSL Units 1 and 2 RCPs. ASME Code Case N-481 allows visual inspections in lieu of volumetric inspections of the pump casing base metal and welds based on a fracture mechanics evaluation.

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, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS).” Specifically, GALL-SLR AMP XI.M12 provides an allowance for continued use of flaw tolerance evaluations performed as part of implementation of ASME Code Case N-481 to address thermal aging embrittlement. GALL-SLR AMP XI.M12 states that no further actions are needed if applicants demonstrate that (1) the original flaw tolerance evaluation performed as part of ASME Code Case N-481 implementation remains bounding and applicable for the subsequent license renewal (SLR) period or, (2) the evaluation is revised to be applicable for 80 years.

For SLR, Westinghouse performed a reconciliation analysis of the original Code Case N-481 evaluation. The current RCS piping loads and 80-year design transients and cycles were considered for the reconciliation. For the fatigue crack growth evaluation for SLR, a comparison to the more recently accepted fatigue crack growth rates were considered for stainless steel in an air environment from Appendix C of the ASME Section XI code.

Westinghouse reconciliation report LTR-SDA-20-099-P/NP was performed for the PSL RCP casings for the 80-year SPEO. The fatigue crack growth evaluations for the PSL Unit 2 RCP casings were reconciled for the 80-year SLR operation and the current ASME Section XI crack growth rate. The report updates the fracture toughness for the RCP casings in accordance with NUREG/CR-4513, Revisions 1 and 2 and since the stability against ductile tearing criterion is satisfied, only the crack growth mechanism is related to fatigue cycles. The report also evaluated the critical flaw sizes and acceptable period of operation based on non-ductile propagation, ductile tearing, and flow stress limit and concluded a postulated flaw will continue to grow until reaching the critical flaw size of 38 percent in about 130 years.

Therefore, the PSL Unit 2 RCP casings meet the material criteria in ASME Code Case N-481 for waiving volumetric examinations of cast austenitic pump casings and inservice volumetric examinations of these RCP casings are not necessary for the 80-year SLR period of extended operation. However, visual (VT-3) examinations of casing inside surfaces, to the extent practical, are prudent whenever an RCP is disassembled for maintenance.

Therefore, the conclusions reached in the original CEOG RCP Code Case N-481 evaluation has been demonstrated to remain valid through the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

19.3.6.5 Crane Load Cycle Limits

A review of design specifications for cranes within the scope of SLR was performed to identify those cranes that comply with Crane Manufacturers Association of America Specification 70 (CMAA-70) 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.

The cranes considered to be a TLAA are those in compliance with NUREG-0612 and in the scope of SLR for their lifting function. The NUREG-0612 cranes are documented in PSL Unit 2 UFSAR Table 9.6-1. The following PSL Unit 2 cranes comply with NUREG-0612 and are included in scope of SLR for their lifting function:

- Charging pump A, B, & C monorails
- Turbine building gantry crane
- Reactor polar crane
- Auxiliary telescoping jib crane
- Refueling machine and hoist
- Fuel transfer machine
- Spent-fuel handling machine
- Refueling canal bulkhead monorail
- Cask storage pool bulkhead monorail
- Spent fuel cask handling crane
- Diesel generator monorails
- Intake structure bridge crane

The Unit 2 cranes comply with the applicable design requirements of ANSI B30.2, CMAA-70, and CMAA-74 as stated in Section 9.6.3.7 of the Unit 2 UFSAR.

The PSL Unit 2 cranes are used primarily during refueling outages. Based on their historical and projected usage, the Unit 2 spent fuel handling machine makes the most lifts at or near its rated capacity. Because the PSL Units 1 and 2 spent fuel handling machines went into service in 1976 and 1983, respectively, and both units began doing full-core offloads after 2000, the PSL Unit 2 spent fuel handing machine is projected to be subjected to more full-core offloads than PSL Unit 1 during the 80-year plant life.

CMAA-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 PSL Unit 2 design specifications and CMAA-70, the applicable service class for the PSL Unit 2 cranes is Class A1. Table 3.3.3.1.3-1 of CMAA-70 states that a range of load cycles from 20,000 to 100,000 is applicable for cranes in Service Class A1 service thus establishing the envelope for the acceptable number of load cycles for this TLAA.

An evaluation has been performed for the PSL Unit 2 spent fuel handling machines and conservatively determined the crane would be subjected to 56,880 load cycles during the 80-year SPEO. This number of lift cycles is less than the 100,000 load cycle limit specified for Class A service.

Therefore, the PSL Unit 2 crane load cycle limits remain valid through the SPEO in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

19.3.6.6 Flaw Tolerance Evaluation for CASS RCS Piping

As part of the PSL Unit 2 original license renewal process, FPL committed to manage the reduction in fracture toughness due to thermal aging of CASS RCS piping components through an aging management program (AMP) which would be consistent with the recommendations of NUREG-1801, AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)." NUREG-1801, AMP XI.M12 requires that the effects of thermal embrittlement in susceptible materials be evaluated to determine the material's susceptibility to thermal aging embrittlement based on casting method, molybdenum content and percent delta ferrite. NUREG-1801 also requires that the aging effects of potentially susceptible components must be managed through either enhanced volumetric examinations or through a plant or component specific flaw tolerance evaluation. FPL chose the flaw tolerance approach to demonstrate that the affected CASS piping components will remain structurally capable of performing their intended safety function during the 60-year license renewal period of extended operation (PEO). The flaw tolerance evaluation for the PEO was performed by Structural Integrity Associates (SI) and consisted of a probabilistic fracture mechanics (PFM) evaluation to determine the tolerable flaw sizes, followed by the performance of a crack growth evaluation with a postulated flaw, to show that the tolerable flaws sizes would not be exceeded during the PEO. The PFM evaluation concluded that the susceptible RCS CASS piping components for PSL Unit 2 are flaw tolerant.

Although not required by NUREG-1801, AMP XI.M12, a one-time baseline ultrasonic (UT) examination of CASS RCS piping components adjacent to welds was performed prior to entering the PSL Unit 2 PEO. This one time examination was considered a program enhancement to detect axial and circumferentially oriented service induced flaws that have at least 25 percent through wall depth. The PSL Unit 2 baseline flaw examinations revealed no existing crack like indications with a 25 percent through wall depth.

For the 80-year subsequent period of extended operation (SPEO), SI prepared Report No. 2001262.402, which documents the results of the flaw tolerance evaluation of CASS RCS piping components for PSL Unit 2. As documented in SI

Report No. 2001262.402, the fracture toughness for the PSL Unit 2 CASS RCS piping components using the updated correlations in NUREG/CR-4513, Revision 2 for the SPEO are comparable to those derived for the PEO using the correlations NUREG/CR-4513 Revision 1. Therefore, the crack growth resistance (J-R) curves used for the PEO remain applicable for the 80-year SPEO. Since the J-R curves for the PEO remain applicable for SPEO, and since the other inputs used in the determination of the tolerable flaw size (stresses and geometry) remain unchanged, the maximum tolerable flaw sizes determined for the PEO also remain applicable for 80-year SPEO.

The flaw tolerance evaluation for the PEO also included a fatigue crack evaluation to ensure that crack growth with a postulated initial flaw size will not exceed the tolerable flaw size during the extended operating period. Updated fatigue crack growth evaluations were performed using the 80-year projected cycles and applying the fatigue crack growth law of ASME Section XI Code Case N-809. For the SPEO, an updated version of crack growth software pc-Crack was used, which eliminated some of the unnecessary conservatisms in the PEO report.

The crack growth evaluation performed for the PSL Unit 2 SPEO using an updated crack growth law for Type 316 stainless steel and 80-year projected cycles show that with an initial postulated quarter thickness flaw with length six times the depth, the tolerable flaw sizes are not reached until after 960 months (80 years) of operation for the susceptible PSL Unit 2 CASS RCS piping components. These results confirm that the thermally aged PSL Unit 2 CASS RCS piping components are demonstrated to be flaw tolerant. Furthermore, since acceptable baseline inspections of the PSL Unit 2 CASS RCS piping components were performed prior to entering the PEO, no further inspections are required to manage thermal aging embrittlement of CASS RCS piping components during the 80-year SPEO.

Therefore, the flaw tolerance evaluation is projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

19.3.6.7 Unit 2 Structural Weld Overlay PWSCC Crack Growth Analyses

Structural weld overlays (SWOLs) were installed on several PSL Unit 2 reactor coolant system (RCS) piping locations to eliminate concerns with stress corrosion cracking of Alloy 182 dissimilar metal welds. The susceptible locations that include SWOLs are as follows:

- Pressurizer surge nozzle
- Pressurizer relief valve nozzles
- Hot leg shutdown cooling nozzles
- Hot leg surge nozzle
- Hot leg drain nozzle

Primary water stress corrosion crack (PWSCC) analyses for the Alloy 182 dissimilar metal welds and butter, extending into the Alloy 52M SWOLs were performed for the current 60-year PEO. The purpose of the analyses was to provide the acceptable period of operation between inspections for each SWOL location based on the crack growth analyses (CGA) performed in accordance with Non-Mandatory Appendix C of

Section XI of the ASME Code with the use of applicable operating transients and associated cycles.

For the 80-year SPEO, Framatome updated the original 60-year PEO analyses to establish the acceptable period of operation between inspections for the SWOL locations. The most limiting acceptable period of operation between inspections for the SPEO is 18.1 years, which corresponds to PSL Unit 2 hot leg surge nozzle.

For the current PEO, the PSL Unit 2 SWOLs are examined in accordance with ASME Code Case N-770-5. Code Case N-770-5 requires the SWOLs to be placed in a population to be examined on a sample basis. Twenty-five percent of the SWOL population is currently examined once in each 10-year inspection interval. This examination requirement remains applicable for the SPEO as the limiting APO of 18.1 years for the SPEO is greater than the required 10-year inspection interval.

The effects of cracking on the intended functions of the PSL Unit 2 RCS piping SWOLs will be managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section 19.2.2.1) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

19.4 Subsequent License Renewal (SLR) Commitments List

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
1	Fatigue Monitoring (19.2.1.1)	X.M1	Continue the existing PSL 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 monitor and track the loss of letdown flow transient during the SPEO. d) Update the plant procedure to identify the corrective action options to take if component specific fatigue limits are approached. e) Update the plant procedure to add additional acceptance criterion associated with HELB CUF criteria.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
2	Neutron Fluence Monitoring (19.2.1.2)	X.M2	Continue the existing PSL Neutron Fluence Monitoring AMP, including enhancement to: a) Follow the related industry efforts, such as by the Pressurized Water Reactor Owners Group (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-18124-NP-A or similar methodology for the determination of RPV fluence in regions above or below the active fuel region.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			b) Include justification that draws from Westinghouse's NRC approved RPV fluence calculation methodology and includes 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.	
3	Environmental Qualification of Electric Equipment (19.2.1.3)	X.E1	Continue the existing PSL 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, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
4	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (19.2.2.1)	XI.M1	Continue the existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
5	Water Chemistry (19.2.2.2)	XI.M2	Continue the existing PSL Water 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.: PSL2: 10/06/2042
6	Reactor Head Closure Stud Bolting (19.2.2.3)	XI.M3	Continue the existing PSL Reactor Head Closure Stud Bolting AMP, including enhancement to: a) Procure reactor head closure stud materials to limit the maximum yield strength of replacement material to a measured yield strength less than 150 ksi and a maximum tensile strength of 170 ksi.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			b) Preclude the use of molybdenum disulfide (MoS_2) lubricant for the reactor head closure stud bolting.	
7	Boric Acid Corrosion (19.2.2.4)	XI.M10	Continue the existing PSL Boric Acid Corrosion AMP, including enhancement to: a) Include other potential means to help in the identification of borated water leakage, such as the following, in order to identify potential borated water leaks inside containment that have not been detected during walkdowns and maintenance: • Airborne radioactivity monitoring • Humidity monitoring (for trending increases in humidity levels due to unidentified RCS leakage) • Temperature monitoring (for trending increases in room/area temperatures due to unidentified RCS leakage) • Containment air cooler thermal performance monitoring (for corroborating increases in containment atmosphere temperature or humidity with decreases in cooler efficiency due to boric acid plate out) b) Include a requirement in the PSL Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components AMP implementing documents to document evidence of boric acid residue (plating out of moist steam) inside containment cooler housings or similar locations such as cooling unit drain pans and to enter evidence in to the corrective action program to be evaluated under a boric acid corrosion control (BACC) program evaluation.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
8	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (19.2.2.5)	XI.M11B	Continue the existing PSL 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 alloy 600 material 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, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
9	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (19.2.2.6)	XI.M12	Continue the existing PSL Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
10	Reactor Vessel Internals (19.2.2.7)	XIM.16A	Continue the existing PSL Reactor Vessel Internals AMP, including enhancement to: a) Implement the results of the gap analysis or implement the latest NRC-approved version of MRP-227 if it addresses 80 years of operation.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
11	Flow-Accelerated Corrosion (19.2.2.8)	XI.M17	Continue the existing PSL 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-R4) to ensure the exclusion remains valid and applicable for operation through 80 years. If actual wall thickness information is not available for use in this re-assessment, a representative sampling approach will be used. This re-assessment may result in additional inspections.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			b) Extend the erosion inspection plan for the duration of the SPEO. c) Perform opportunistic visual inspections of internal surfaces during routine maintenance activities to identify degradation. d) 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. e) 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. f) Revise or provide procedure(s) to perform periodic wall thickness measurements of replacement components until the effectiveness of corrective actions have been confirmed. g) 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.	
12	Bolting Integrity (19.2.2.9)	XI.M18	Continue the existing PSL Bolting Integrity AMP, including enhancement to: a) Ensure references to EPRI Reports 1015336, 1015337, and NUREG-1339 are added and guidance incorporated, as appropriate, for selection of bolting material and the use of lubricants and sealants.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			b) Ensure lubricants containing molybdenum disulfide (MoS_2) or other lubricants containing sulfur will not be used for pressure-retaining bolting. c) Ensure that the maximum yield strength of replacement or newly procured pressure-retaining bolting material will be limited to an actual yield strength less than 150 ksi (1,034 MPa). In addition, 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 for pressure retaining bolting. For 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) 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). The alternative testing will be completed on a case-by-case basis through: • Visual inspections of closure bolting during maintenance activities that make the bolt heads accessible and bolt threads visible;	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• Visual inspection for discoloration is conducted 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, or; • Thermography testing when the temperature of the fluid is higher than ambient conditions. e) 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. f) Ensure that closure bolting inspections will include consideration of the guidance applicable for pressure boundary bolting in NUREG-1339 and in EPRI NP-5769. g) 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 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.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			h) Evaluate leakage monitoring and sample expansion and add additional inspections if inspection results do not meet acceptance criteria as described in NUREG-2191, Chapter XI.M18, Element 7.	
13	Steam Generators (19.2.2.10)	XI.M19	Continue the existing PSL Steam Generators AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
14	Open-Cycle Cooling Water System (19.2.2.11)	XI.M20	Continue the existing PSL Open-Cycle Cooling Water System AMP, including enhancement to: a) Ensure program tests and inspections follow site procedures that include requirements for items such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes. b) Ensure the primary program document and applicable procedures and preventive maintenance activities include trending of wall thickness measurements at locations susceptible to ongoing degradation due to specific aging mechanisms (e.g., MIC). The PSL Open-Cycle Cooling Water System AMP will adjust the monitoring frequency based on the trending. c) Ensure the primary program document and applicable procedures and preventive maintenance activities clarify that when components do not meet or are projected to not meet the next inspection’s minimum wall thickness requirements, the program includes reevaluation, repair, or replacement such components. d) Ensure that all above-ground, large-bore, safety-related ICW piping is replaced with AL6XN stainless steel piping.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			e) Clarify within the applicable procedures, specifications, and preventive maintenance activities that the 100% internal inspections of the ICW header piping will be supplemented with localized volumetric examinations (UT, radiography, etc.) as applicable for areas where visual inspection alone is not adequate or as needed to determine the extent of degradation.	
15	Closed Treated Water Systems (19.2.2.12)	XI.M21A	Continue the existing PSL 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 on the internal surfaces exposed to the treated closed recirculating cooling water. 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 on the internal surfaces exposed to the treated closed recirculating cooling water. c) Ensure that visual inspections of closed treated water system components' internal surfaces are conducted whenever the system boundary is opened. When opportunistic visual inspections are conducted while the system boundary is open, they 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. d) 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,	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

			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 PSL is a two-Unit plant. e) 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. f) Ensure that the new inspection and test procedure(s) and/or preventive maintenance requirements report and evaluate any detectable loss of material, cracking, or fouling associated with surfaces exposed to the treated closed recirculating cooling water per the PSL corrective action program. g) Ensure that the following additional inspections and actions are required if a post-repair/replacement inspection or subsequent inspection of surfaces exposed to the treated closed cooling water environment fails to meet acceptance criteria: • The number of increased inspections is determined in accordance with the PSL 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	

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			address the associated causes. Since PSL 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.	
16	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (19.2.2.13)	XI.M23	Continue the existing PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, including enhancement to: a) Update the implementing procedure to state that, for the in-scope systems that are infrequently in service, such as the containment polar cranes, periodic inspections are performed once every refueling cycle just prior to use. b) Update the implementing procedure and inspection procedures state their respective visual inspection frequencies required by ASME B30.2-2005. According to ASME B30.2-2005, inspections are performed within the following intervals: • “Periodic” visual inspections by a designated person are required and documented yearly for normal service applications • 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 ASME B30.2-2005 paragraph 2-2.1.3 (i.e., periodic inspection) c) Update the implementing procedure to ensure that the inspection procedures for the individual load handling systems are clearly identified and referenced.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			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 in accordance with ASME B30.2-2005. e) Update the governing procedure to state that repairs made to NUREG-0612 load handling systems are performed as specified in ASME B30.2-2005.	
17	Compressed Air Monitoring (19.2.2.14)	XI.M24	Continue the existing PSL 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: a) Incorporate the air quality provisions provided in the guidance of the EPRI TR-108147 and consider the related guidance in the ASME OM-2012, Division 2, Part 28. b) Perform opportunistic visual inspections of accessible internal surfaces for signs of corrosion and abnormal corrosion products that might indicate a loss of material within the system. c) Include inspections of internal air line surfaces downstream of the instrument air dryers and emergency diesel generator air start dryers with maintenance, corrective, or other activities that involve opening of the component or system. d) Include inspection methods for the opportunistic inspections with guidance of standards or documents such as ASME OM-2012, Division 2, Part 28. e) Review air quality test results.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			f) Include requirements for better long term trending of negative trends, more thorough documentation, and proactive aging management. g) Include monitoring and trending guidance from ASME OM-2012, Division 2, Part 28 as applicable.	
18	Fire Protection (19.2.2.15)	XI.M26	Continue the existing PSL Fire Protection AMP, including enhancement to: a) Enhance plant procedures to specify that penetration seals will be inspected for indications of increased hardness and loss of strength such as cracking, seal separation from walls and components, separation of layers of material, rupture, and puncture of seals. b) Enhance plant procedures to specify that subliming, cementitious, and silicate materials used in fireproofing and fire barriers will be inspected for loss of material, change in material properties, and cracking/delamination. c) Enhance plant procedures to specify that any loss of material (e.g., general, pitting, or crevice corrosion), cracking, or elastomer degradation (e.g., hardening, loss of strength, or shrinkage) as applicable to the fire damper assembly is unacceptable. d) Enhance plant procedures to require projection of identified degradation to the next scheduled inspection for all monitored fire protection SSCs, where practical. e) Enhance plant procedures to require that projections are 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.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

Table 19-3
List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
19	Fire Water System (19.2.2.16)	XI.M27	Continue the existing PSL Fire Water System AMP, including enhancement to: a) Update the governing AMP procedure to clearly state which procedures perform visual inspections for detecting loss of material, as well as state which procedures perform surface examinations or ASME Code, Section XI, VT-1 visual examinations for identifying SCC of copper alloy (>15% Zn) valve bodies, nozzles, and strainers. 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. The 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% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 19 components per population at each Unit is inspected. Where practical, the inspections will focus on the bounding or lead components most susceptible to aging. 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 inspection/testing procedures and create new procedures to incorporate the surveillance requirements stated in NUREG-2191, Section XI.M27, Element 4 and Table XI.M27-1, which are based on NFPA 25, 2011 edition. This includes testing	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042 Implement the AMP and start inspections and tests no earlier than 5 years prior to the SPEO (04/06/2038). Perform the 10-year City Water Storage Tank bottom inspections within 10 years prior to the SPEO (04/06/2033).

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			or replacement of fast-response and traditional sprinkler heads that have been in service for 20 or 50 years, respectively, in accordance with NFPA 25. d) Update the governing AMP procedure and trending procedure to state that where practical, degradation identified is projected 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. Results of flow testing (e.g., buried, and underground piping, fire mains, and sprinklers/spray nozzles), flushes, and wall thickness measurements are monitored and trended by either the Engineering or the 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 PSL 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.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			g) Update spray and sprinkler system flushing procedures to enable trending of data. Specifically, the existing flushing procedures (listed below) will be revised to document and trend deposits (scale or foreign material). Recommended methods for trending deposits may include the following as feasible: • Inspectors will take photographs of deposits. • Inspectors will measure the weight of the deposits. • Inspectors will measure elapsed time taken to complete a flush (i.e., the time required for the flushing water to turn an acceptable color). The documentation above will be maintained by the AMP owner for comparing and trending inspection/test results. Existing flushing procedures (listed below), as well as new flushing procedures, will include steps to compare the amount of deposits to the previous inspections' results, and if the trend is negative or if the projected solids for the next inspection/test/flush are anticipated to exceed an acceptable amount that would impact the system intended function, then the PSL Corrective Action Program will be utilized to drive improvement. Additionally, identified deposits will be evaluated for potential impact on downstream components, such as sprinkler heads or spray nozzles. h) Update the governing AMP procedure to state that identified wall loss greater than the manufacturers tolerance will be entered into the corrective action program process for engineering evaluation. i) Update the governing AMP procedure to point to the inspection procedures which inspect the wall thicknesses and compare wall loss to the manufacturers tolerance. j) Update the governing AMP procedure to state that internal inspection, flow testing, and flushing procedures/ preventive	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			maintenance activities must demonstrate that no loose fouling products exist in the systems that could cause flow blockage in the sprinklers or deluge nozzles. k) Update the governing AMP procedure and respective pipe inspection procedures to state that if an obstruction inside piping or sprinklers is detected during pipe inspections, the material is removed and the inspection results are entered into the PSL 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 Annex 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 PSL corrective action program. If a failure occurs (e.g., a through-wall leak or blockage impacting operability), the failure mechanism shall be identified and used to determine the most susceptible system locations for additional inspections, including consideration to the other Unit systems as driven by the corrective action program. When piping is replaced prior to failure, due to concerns with wall thinning or blockage, inspections are considered for similar areas of the system to determine the presence and extent of degradation. The implementation of these augmented inspection actions provides reasonable assurance that the fire water system will continue to perform its function adequately through the SPEO. l) Update the existing flow test procedure and the existing deluge system flush/test procedure enhanced with new main drain tests 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 will be conducted. The number of increased tests is determined in accordance with the PSL corrective action	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			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 will be conducted to determine the further extent of tests. Since PSL is a two-Unit site, additional tests include inspections at both of the Units with the same material, environment, and aging effect combination. m) Update the primary program procedure and applicable preventive maintenance activities to state that, as a contingency, if degradation mechanisms such as MIC, erosion, or recurring loss of material due to internal corrosion were to occur, 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 PSL 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 PSL 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	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			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.	
20	Outdoor and Large Atmospheric Metallic Storage Tanks (19.2.2.17)	XI.M29	Continue the existing PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP, including enhancement to: a) Create a new procedure, and/or associated preventive maintenance activities, to: • Address the interfaces, handoffs, and overlaps between the PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP and the following AMPs: ○ PSL Structures Monitoring AMP; ○ PSL External Surfaces Monitoring of Mechanical Components AMP; ○ PSL Water Chemistry AMP; ○ PSL One-Time Inspection AMP, ○ PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP; and ○ PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP. • Direct periodic (18-month interval) visual inspection of tank-to-concrete caulking/sealants, with mechanical manipulation as appropriate. Update or reactivate existing caulking/sealant inspection preventive maintenance activities and create new caulking/sealant inspection preventive maintenance activities as needed. These	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042 Implement the AMP and start the 10-year interval inspections no earlier than 10 years prior to the SPEO (04/06/2033). Start the one-time inspections no earlier than 5 years prior to the SPEO (04/06/2038).

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			caulking/sealant inspections are performed by the PSL Structures Monitoring AMP. • Direct the 10-year bottom thickness measurement of the U2 RWT, U2 PWST, and the U2 CST, using low-frequency electromagnetic testing (LFET) techniques with follow-on UT examination, as necessary, at discrete tank locations identified by LFET. • Direct baseline one-time interior visual inspections of the U2 RWT. Direct 10-year surface examination inspections of the stainless steel U2 RWT's interior nonwetted surface and exterior surface for evidence of loss of material and cracking. The surface examinations will inspect 25 1-square-foot sections or 25 1-linear-foot sections of welds. If evidence of cracking is identified, then a surface examination is also performed to determine the extent of the cracking. • Clarify that subsequent inspections are conducted in different locations unless this AMP includes a documented basis for conducting repeated volumetric and surface 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 inspections and tests within the scope of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) follow procedures consistent with the ASME Code, including ASME Code Section XI. Non-ASME Code inspections and tests follow site procedures that include considerations such as lighting,	

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			distance offset, surface coverage, presence of protective coatings, and cleaning processes.
			• Clarify that where practical, identified degradation is projected until the next scheduled inspection, or in the case of one-time inspections, identified degradation is projected to the end of the SPEO.
			• Clarify that results are evaluated against acceptance criteria to confirm or adjust timing of subsequent inspections, or in the case of one-time inspections, schedule follow-up inspections.
			• State the acceptance criteria as follows:
			  ○ No degradation of paints or coatings (e.g., cracking, flakes, or peeling), or the U2 PWST internal floating roof;
			  ○ No non-pliable, cracked, or missing caulking/sealant for the tank bottom interface;
			  ○ No indications of cracking of a stainless steel tank (U2 RWT), and;
			  ○ Measured or projected tank bottom thickness must be greater than 87.5% of the nominal plate thickness.
			• 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 or repair/replace the degraded component as needed.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			○ Repair or replace the degraded component as determined by engineering evaluation and perform follow-up examinations. For one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals. ○ For other sampling-based inspections (e.g., 20%, 25 locations) the smaller of five additional inspections or 20% of the inspection population is conducted. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause is conducted to determine the further extent of inspection. The additional inspections include inspections at all of the Units with the same material, environment, and aging effect combination. Sample expansion inspections that happen in the next inspection interval are part of the preceding interval. b) Perform baseline one-time interior visual inspections of the U2 RWT. Perform 10-year surface examination inspections of the stainless steel U2 RWT's interior nonwetted surface and exterior surface for evidence of loss of material and cracking. The surface examinations will inspect 25 1-square-foot sections or 25 1-linear-foot sections of welds. If evidence of cracking is identified, then a surface examination is also performed to determine the extent of the cracking. c) Perform 10-year LFET tank bottom thickness examinations of the U2 RWT, U2 PWST, and the U2 CST, with follow-on UT at discrete locations.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
21	Fuel Oil Chemistry (19.2.2.18)	XI.M30	Continue the existing PSL Fuel Oil Chemistry AMP, including enhancement to: a) Address the analysis of stored fuels in the day tanks describing analytical techniques and test frequencies for determining water and sediment content, total particulate concentration, and microbiological contamination levels. b) Address periodic tank cleaning, and visual or alternative internal inspections of the day tanks. c) Drain, clean, and visually inspect all DOSTs at least once during the 10-year period prior to the SPEO, and repeat the inspection at least once every 10 years. d) Require any pressure retaining boundary degradation identified during visual inspection be supplemented with volumetric (UT) wall thickness testing including bottom thickness measurements for the DOSTs if warranted. e) Prior to the SPEO, perform a one-time inspection of selected components exposed to diesel fuel oil in accordance with the PSL One-Time Inspection AMP to verify the effectiveness of the PSL Fuel Oil Chemistry AMP. f) Enhance monitoring and trending by; • Perform periodic fuel oil sampling of the day tanks. • Clarify that the sampling specifically monitors the following parameters for trending purposes: water content, sediment content, biological activity, and total particulate concentration for all DOSTs and day tanks. • Update frequency of ASTM D975 analysis to quarterly.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042 Implement the AMP and start the one-time and 10-year interval inspections no earlier than 10 years prior to the SPEO (04/06/2033).

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			g) Include the following monitoring and trending features in visual and volumetric inspection methodology: • Identified degradation is projected until the next scheduled inspection, where practical. • Evaluate the 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. h) Provide acceptance criteria, consistent with industry standards, for the testing requirement and approach used to detect the presence of water, particulates, and microbiological activity in stored diesel fuel within all DOSTs and day tanks. i) Include the following acceptance criteria features in visual and volumetric inspection methodology: • Report any degradation of the tank (including all DOSTs and day tanks) internal surfaces and evaluate using the corrective action program. • Evaluate thickness measurements of the DOST tank bottom against the design thickness and corrosion allowance. j) Provide corrective actions, such as addition of a biocide, to be taken should testing detect the presence of microbiological activity in stored diesel fuel. k) Address performing corrective actions to prevent recurrence when the specified limits for fuel oil standards are exceeded during periodic surveillance.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
22	Reactor Vessel Material Surveillance (19.2.2.19)	XI.M31	Continue the existing PSL Reactor Vessel Material Surveillance AMP, including an incremental adjustment to the approved capsule withdrawal schedule to withdraw and test the surveillance capsule located at 277° in accordance with the NRC approved withdrawal schedule.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
23	One Time inspection (19.2.2.20)	XI.M32	Implement the new PSL One-Time Inspection AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042 Implement the AMP and start the one-time inspections no earlier than 10 years prior to the SPEO (04/06/2033).
24	Selective Leaching (19.2.2.21)	XI.M33	Implement the new PSL 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.: PSL2: 10/06/2042 Implement the AMP and start the one-time and 10-year interval inspections no earlier than 10 years prior to the SPEO (04/06/2033).

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
25	ASME Code Class 1 Small-Bore Piping (19.2.2.22)	XI.M35	Continue the existing PSL ASME Code Class 1 Small-Bore Piping AMP, which includes: a) Perform one-time inspection of small-bore piping using the methods, frequencies, and acceptance criteria as outlined in NUREG-2191, Section XI.M35. 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, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042 Implement the AMP and start the inspections within 6 years prior to the SPEO (04/06/2037).
26	External Surfaces Monitoring of Mechanical Components (19.2.2.23)	XI.M36	Continue the existing PSL External Surfaces Monitoring of Mechanical Components AMP, including enhancement to: a) Indicate the material and environment combinations where external examinations could be credited to manage the aging effects of the internal surfaces of components as detailed in the PSL External Surfaces Monitoring of Mechanical Components AMP. b) Incorporate the aging management activities currently performed for external corrosion of insulated piping at PSL in the PSL External Surfaces Monitoring of Mechanical Components program procedure. c) Ensure all components made of stainless steel, aluminum, or copper alloys with greater than 15% Zn or 8% Al inspected by this program will have periodic visual or surface examinations conducted to manage cracking. d) Monitor the aging effects for elastomeric and flexible polymeric components through a combination of visual inspection and manual or physical manipulation of the material. Manual or physical manipulation of the material will include touching, pressing on, flexing, bending, or otherwise manually interacting	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			with the material. The purpose of the manual manipulation will be 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. Flexing of polymeric components (e.g., expansion joints) 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) will be conducted to detect potential reduction in impact strength as indicated by a crackling sound or surface cracks when flexed. Examples of inspection parameters for elastomers and polymers will include: • 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. e) Specify that this program will also manage hardening or loss of strength, loss of preload for heating, ventilation, and air conditioning (HVAC) closure bolting, and blistering using visual inspections. In addition, physical manipulation will be used to manage hardening or loss of strength and reduction in impact strength.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			f) Specify that, when required by the ASME Code, inspections will be conducted in accordance with the applicable code requirements. And, when non-ASME Code inspections and tests are required, inspections will follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, and presence of protective coatings. Inspections, except those for cracking and under insulation, will be performed every refueling outage. g) Ensure that periodic visual inspections or surface examinations will be conducted on components made of stainless steel, aluminum, or copper alloys with greater than 15% Zn or 8% Al to manage cracking every 10 years during the SPEO and other inspections will be performed at a frequency not to exceed one refueling cycle. 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 provide reasonable assurance that the components' intended functions are maintained. h) Specify that, when inspecting to manage cracking of a component's material, either surface examinations conducted in accordance with plant-specific procedures or ASME Code Section XI VT-1 inspections (including those inspections conducted on non-ASME Code components) are conducted on each component inspected. An inspection requires that at least 20% of the surface area of the component is inspected, unless the component is measured in linear feet, such as piping. Any combination of 1-ft length sections and components can be used to meet the recommended extent of 20% of the population of materials and environment combinations, with a maximum of 25 inspections required in each population. An inspection of a component in a more severe environment may be credited as an inspection for the specified environment and for the same material and aging effects in a less severe environment (e.g., an	

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			outdoor air environment is more severe than an indoor uncontrolled air environment which is more severe than an indoor controlled air environment, assuming that there are no borated water leaks in the indoor environments). i) Specify that, when inspecting insulated components in an outdoor environment or that may be exposed to condensation in an indoor environment, that the population and sample sizes used for inspections will be determined based on the material type (e.g., steel, stainless steel, copper alloy, aluminum) and environment (e.g., air outdoor, air accompanied by leakage) combination. 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-ft axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Alternatively, any combination of a minimum of twenty-five 1-ft axial length sections and components for each material type is inspected, with a maximum of 25 inspections required in each population. j) Ensure that visual inspections 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. 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. 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. The sample	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			size for manipulation will be at least 10% of available surface area. k) Indicate that the following alternatives to removing insulation after the initial inspection will be acceptable: i. Subsequent inspections may consist of examination of the exterior surface of the insulation with sufficient acuity to detect indications of damage to the jacketing or protective outer layer (if the protective outer layer is waterproof) of the insulation when the results of the initial inspections meet the following criteria: • No loss of material due to general, pitting, or crevice corrosion beyond that which could have been present during initial construction is observed during the first set of inspections, and • No evidence of SCC is observed during the first set of inspections. If: (a) the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or jacketing, (b) there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), or (c) the protective outer layer (where jacketing is not installed) is not waterproof, then periodic inspections under the insulation should continue as conducted for the initial inspection. ii. Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of corrosion under insulation is low for tightly adhering insulation. Tightly adhering insulation is considered to be a separate population from the remainder	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			of insulation installed on in-scope components. The entire population of in-scope piping that has tightly adhering insulation is visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections are not credited towards the inspection quantities for other types of insulation. l) Specify that 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. m) Include evaluation and acceptance guidance from EPRI TR-1009743, "Aging Identification and Assessment Checklist," for visual/tactile inspections where appropriate. n) Specify that inspections to detect cracking in aluminum, stainless steel, and applicable copper alloy components will have additional inspections conducted if one of the inspections does not meet the 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. The number of increased inspections will be determined in accordance with the site's corrective action process; however, 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 is inspected, whichever is less. The additional inspections are completed within the interval in which the original inspection was conducted. If 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. Additional samples	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			will be inspected for any recurring degradation to provide reasonable assurance that corrective actions appropriately address the associated causes. The additional inspections include populations with the same material, environment, and aging effect combinations at both Unit 1 and Unit 2. o) Require that any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, will have their inspection frequencies adjusted as determined by the corrective action program.	
27	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (19.2.2.24)	XI.M38	Implement the new PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
28	Lubricating Oil Analysis (19.2.2.25)	XI.M39	Continue the existing PSL Lubricating Oil Analysis AMP, including enhancement to: a) Perform sampling and testing of old oil following periodic oil changes, or on a schedule consistent with equipment manufacturer's recommendations or industry standards [e.g., ASTM D6224-02]. Plant specific OE associated with oil systems may also be used to adjust the schedule for periodic sampling and testing, when justified by prior sampling results. b) Ensure guidance indicates that 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).	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
29	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (19.2.2.26)	XI.M40	Continue the existing PSL Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP, including enhancement to: a) Inspect and test Metamic® inserts on a frequency dependent on the condition of the neutron-absorbing material and determined and justified with PSL-specific OE. For each Metamic® insert selected for surveillance, the maximum interval between each inspection and between each coupon test is not to exceed 10 years, regardless of OE. b) Compare observations and measurements from the periodic inspections and coupon testing to baseline information or prior measurements and analyses for trending analysis, projecting future degradation, and projecting the future subcriticality margin of the spent fuel pool (SFP). This trending will also consider differences in exposure conditions, venting, spent fuel rack differences, etc. for each Metamic® insert or coupon selected for surveillance. c) Initiate corrective actions (e.g., add neutron-absorbing capacity with an alternate material, or apply other available options) to maintain the subcriticality margin if the results from measurements and analysis indicate that the 5% subcriticality margin cannot be maintained because of current or projected degradation of the neutron-absorbing material. d) Manage aging effects associated with the Boral® panels in the SFP cask area by monitoring for loss of material and changes in dimension that could result in loss of neutron-absorbing capability of the Boral® panels. Monitor parameters associated with the physical condition of the Boral® panels and include in-situ gap formation, geometric changes as observed from coupons or in situ, and decreased boron-10 areal density, etc. The parameters monitored are directly related to determination of the loss of material or loss of neutron absorption capability of the Boral® panels. These parameters are monitored using coupon and/or	Complete the initial Boral® testing and inspections no later than 6 months prior to the SPEO, i.e.: PSL2: 10/06/2042

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			direct in-situ testing of the Boral® panels to identify their associated loss of material and degradation of neutron-absorbing capacity. The frequency of the inspection and testing depends on the condition of the neutron-absorbing material and is determined with site-specific OE; however, the maximum interval between these inspections is not to exceed 10 years, regardless of OE. Compare the Boral® inspection and testing measurements to baseline values for trending analysis and projecting future panel degradation and SFP subcriticality margins. The degradation trending must be based on samples that adequately represent the entire Boral® panel population, and the trending must consider differences in sample exposure conditions, differences in spent fuel cask racks, and possibly other considerations. The new Boral® panel surveillance acceptance criteria for the obtained inspection, testing, and analysis measurements must ensure that the 5% subcriticality margin for the SFP will be maintained, otherwise corrective actions need to be implemented.	
30	Buried and Underground Piping and Tanks (19.2.2.27)	XI.M41	Implement the new PSL Buried and Underground Piping and Tanks AMP. a) Install cathodic protection systems and perform effectiveness reviews in accordance with Table XI.M41-2 in NUREG-2191, Section XI.M41. b) If after five years of operation the cathodic protection system does not meet the effectiveness acceptance criteria defined by NUREG-2191, Tables XI.M41-2 and -3 (-850 mV relative to a CSE, instant off, for at least 80% of the time, and in operation for at least 85% of the time), FPL commits to performing two additional buried steel piping inspections beyond the number required by Preventive Action Category F resulting in a total of	Implement AMP and start inspections no earlier than 10 years prior to the SPEO (04/06/2033). Install cathodic protection systems no later than 10 years prior to the SPEO (04/06/2033). Complete pre-SPEO inspections no later than 6 months or the last RFO prior to SPEO i.e.: PSL2: 10/06/2042

Table 19-3
List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			thirteen (13) inspections being completed 6 months prior to the SPEO.	
31	Internal Coatings/Linings For In-scope Piping, Piping Components, Heat Exchangers, and Tanks (19.2.2.28)	XI.M42	Implement the new PSL 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.: PSL2: 10/06/2042 Implement the AMP and perform baseline inspections no earlier than 10 years prior to the SPEO (04/06/2033).
32	ASME Section XI, Subsection IWE (19.2.2.29)	XI.S1	Continue the existing PSL 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” and EPRI TR-104213, “Bolted Joint Maintenance & Application Guide.” b) Augment existing procedures to specify that for structural bolting consisting of ASTM A325, ASTM A490, and equivalent materials, 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 implement periodic supplemental surface or enhanced visual examinations at intervals no greater than 10 years to detect cracking due to cyclic loading of all	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042 Start the one-time inspections for cracking due to SCC no earlier than 5 years prior to the SPEO (04/06/2038).

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			non-piping penetrations (hatches, electrical penetrations, etc.) that are subject to cyclic loading but have no current licensing bases fatigue analysis and are not subject to local leak rate testing. d) Augment existing procedures to implement supplemental one-time surface or enhanced visual examinations, performed by qualified personnel using methods capable of detecting cracking, 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. These inspections are intended to confirm the absence of SCC aging effects. If SCC is identified as a result of the supplemental one-time inspections, additional inspections will be conducted in accordance with the site's corrective action process. This will include one additional penetration with dissimilar metal welds associated with greater than 140°F stainless steel piping systems for each Unit until cracking is no longer detected. Periodic inspection of subject penetrations with dissimilar metal welds for cracking will be added to the PSL ASME Section XI, Subsection IWE AMP if necessary, depending on the inspection results. e) Augment existing procedures to implement a one-time supplemental volumetric inspection of metal shell surfaces that samples randomly selected as well as focused locations susceptible to loss of thickness due to corrosion from the inaccessible side if triggered by plant-specific OE identified through code inspections after the date of issuance of the first renewed license for each unit. This sampling is conducted to demonstrate, with 95% confidence, that 95% of the accessible portion of the metal shell is not experiencing greater than 10% wall loss.	

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
33	ASME Section XI, Subsection IWF (19.2.2.30)	XI.S3	Continue the existing PSL ASME Section XI, Subsection IWF AMP, including enhancement to: a) Identify the population of ASME Class 1, 2, and 3 high-strength structural bolting greater than one-inch nominal diameter within the boundaries of IWF-1300. b) 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. c) Augment existing procedures to specify the use of high-strength bolt storage requirements discussed in Section 2 of RCSC (Research Council for Structural Connections) publication “Specification for Structural Joints Using ASTM A325 or A490 Bolts,” for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts. d) 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. e) Augment existing procedures to specify that accessible sliding surfaces are monitored for significant loss of material due to wear and accumulation of debris or dirt. f) 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. g) Augment existing procedures to specify that, for component supports with high-strength bolting greater than one-inch nominal	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042 Start the one-time inspection no earlier than 5 years prior to the SPEO (04/06/2038).

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			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. A representative sample of bolts will be inspected during the inspection interval prior to the start of the SPEO and in each 10-year period during the SPEO. The sample will be 20% of the population (for a material / environment combination) up to a maximum of 25 bolts. h) 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. i) 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; and • Cracked or sheared bolts, including high-strength bolts, and anchors; and loss of material, cracking.	
34	10 CFR Part 50, Appendix J (19.2.2.31)	XI.S4	Continue the existing PSL 10 CFR Part 50, Appendix J AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

Table 19-3
List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
35	Masonry Walls (19.2.2.32)	XI.S5	Continue the existing PSL Masonry Walls AMP, including enhancement to: a) Revise the implementing procedure to monitor and inspect for gaps between the supports and masonry walls that could potentially impact the intended function or potentially invalidate its evaluation basis. b) Revise the implementing procedure to include specific monitoring, measurement, and trending of 1) widths and lengths of cracks in masonry walls and mortar joints, and 2) gaps between supports and masonry walls. c) Revise the implementing procedure to include specific guidance for the assessment of the acceptability of the widths and lengths of cracks in masonry walls and mortar joints and of gaps between supports and masonry walls, using evaluation bases established in response to IE Bulletin 80-11 to confirm that the degradation has not invalidated the original evaluation assumptions or impacted the capability to perform the intended functions.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
36	Structures Monitoring (19.2.2.33)	XI.S6	Continue the existing PSL Structures Monitoring AMP, including enhancement to: a) Monitor and inspect steel edge supports on masonry walls. b) Specify the use of high-strength bolt storage requirements discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts. c) Inspect concrete structures for increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			d) Inspect elastomers for loss of material and loss of strength. e) Inspect stainless steel and aluminum components for pitting and crevice corrosion, and evidence of cracking due to SCC. f) Include monitoring and trending of leakage volumes and chemistry for signs of concrete or steel reinforcement degradation if active through-wall leakage or groundwater infiltration is identified. g) Include tactile inspection in addition to visual inspection of elastomeric elements to detect hardening. h) Include evidence of water in-leakage as a finding requiring further evaluation. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessment may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the water. i) Address the aggressive groundwater/soil environment to account for the extent of the degradation experienced. Specific requirements include evaluations, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed 5 years. j) Require inspections of the Condensate Storage Tank (CST) and Auxiliary Feedwater (AFW) Structures and Piping Inspections in the Trenches every third refueling outage, which will ensure that these inspections are performed at least once per 5 years.	

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
37	Inspection of Water-Control Structures Associated with Nuclear Power Plants (19.2.2.34)	XI.S7	Continue the existing PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP, including enhancement to: a) Revise the implementing procedure to specify the use of high-strength bolt storage requirements discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts. b) Revise the implementing procedure to state that further evaluation of evidence of groundwater infiltration or through-concrete leakage may also include destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels, and that assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the leakage water if leakage volumes allow. c) Revise the severe weather implementing procedure to include performance of structural inspections after major unusual events such as hurricanes, floods, or seismic events.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
38	Protective Coating Monitoring and Maintenance (19.2.2.35)	XI.S8	Continue the existing PSL Protective Coating Monitoring and Maintenance AMP, including enhancement to: a) Ensure the implementing documents reference ASTM D5163-08 and clarify the parameter monitored to include blistering, cracking, rusting or physical damage. b) Ensure any follow-up inspections are performed by individuals trained and certified in the applicable reference standards of ASTM Guide D5498-12. c) Ensure inspections include the specific inspection and documentation parameters and observation and testing methods	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			listed in ASTM D5163-08 subparagraph 10.2.1 through 10.2.6, 10.3, and 10.4. d) Ensure implementing documents reference the guidance of Regulatory Position C4 of RG 1.54 Revision 3.	
39	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (19.2.2.36)	XI.E1	Continue the existing PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (formerly the Containment Cable Inspection Program), 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, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042 Implement the AMP and start the 10-year interval inspections no earlier than 10 years prior to the SPEO (04/06/2033).
40	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits (19.2.2.37)	XI.E2	Implement the new PSL 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, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
41	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (19.2.2.38)	XI.E3A	Implement the new PSL Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP including the following: a) Perform medium-voltage cable testing on lead-sheathed (submarine) cables, as a one-time test. b) Perform manhole inspections (containing medium-voltage cables in the program) for water accumulations, cable structural supports' integrity, sump pump operability verification, and manhole drainage path integrity on at least an annual basis. c) Perform manhole inspections (containing medium-voltage cables in the program) following a major water event for water accumulations, sump pump operability verification (and associated alarms), and manhole drainage path integrity. d) Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms).	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
42	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (19.2.2.39)	XI.3B	Implement the new PSL Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP including the following: a) Perform sample I&C cable visual inspections and tests (if necessary) at least every six years. b) Perform manhole inspections (containing I&C cables in the program) for water accumulations, cable structural supports'	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			integrity, sump pump operability verification, and manhole drainage path integrity on at least an annual basis. c) Perform manhole inspections (containing I&C cables in the program) following a major water event for water accumulations, sump pump operability verification (and associated alarms), and manhole drainage path integrity. d) Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms).	
43	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (19.2.2.40)	XI.E3C	Implement the new PSL Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP including the following: a) Perform periodic manhole inspections to prevent inaccessible in-scope low-voltage power cables from being exposed to water accumulations in low-voltage power cable manholes, vaults, and conduits and removing water, as needed, but at least once every year. Inspections are also to be performed after event-driven occurrences, such as heavy rain or flooding. 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 to be inspected, and their operation verified periodically. b) Perform periodic visual inspections of low-voltage power cables accessible from manholes, vaults, or other underground	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			raceways for jacket surface abnormalities at least once every 6 years. c) Perform initial low-voltage power cable testing on a sample population to determine the condition of the electrical insulation. One or more tests may be required based on cable type, application, and electrical insulation material to determine the age-related degradation of the cable insulation. Inaccessible low-voltage power cables designed for continuous wetting or submergence are also included in this AMP. The need for additional periodic tests and inspections is determined by the test/ inspection results as well as industry and plant-specific OE. d) Inspect manholes equipped with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables at least once every five years, if supported by plant OE. Inspections of manholes with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms).	
44	Metal Enclosed Bus (19.2.2.41)	XI.E4	Implement the new PSL Metal Enclosed Bus AMP.	Implement AMP and complete initial inspections no later than 6 months prior to the SPEO, i.e.: PSL2: 10/06/2042

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List of Unit 2 SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
45	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (19.2.2.42)	XI.E6	Implement the new 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, or no later than the last refueling outage prior to the SPEO, i.e.: PSL2: 10/06/2042
46	High-Voltage Insulators (19.2.2.43)	XI.E7	Implement the new High-Voltage Insulators AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
47	Pressurizer Surge Line (19.2.2.44)	N/A – PSL Site-Specific Program	Continue the existing PSL Pressurizer Surge Line AMP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
48	Nonsafety-related SSCs that are not Directly Connected to Safety-related SSCs but have the Potential to Affect Safety- Related SSCs Through Spatial Interactions Screening Document	N/A	Minimize the potential for indoor abandoned equipment outside containment to leak or spray on safety-related equipment by performing the following: a) Update plant procedures to require the periodic venting and draining of indoor abandoned equipment located outside containment that is directly connected to in-service systems. b) Verify that abandoned equipment that is no longer directly connected to in-service systems is vented and drained.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
49	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 corresponding aging management recommendations, including: a) Evaluate their applicability to the PSL Unit 2 primary shield wall and associated reactor vessel supports. b) Update design calculations, as appropriate. c) Develop an informed site-specific program, if needed.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: PSL2: 10/06/2042
50	Quality Assurance Program (19.1.3)	Appendix A	Continue the existing FPL QA Program at PSL.	Ongoing
51	Operating Experience Program (19.1.4)	Appendix B	Continue the existing PSL OE Program.	Ongoing

Appendix A2
USFAR Markup

This section provides a markup of the PSL Unit 2 UFSAR delineating UFSAR changes that will be required for subsequent license renewal.

Control element assemblies (CEAs) are capable of holding the core sub-critical at hot zero power conditions with margin following a trip even with the most reactive CEA stuck in the fully withdrawn position.

Fuel rod clad is designed to maintain cladding integrity throughout fuel life. Fission gas release within the rods and other factors affecting design life are considered for the maximum expected exposures.

The reactor and control systems are designed so that any xenon transients are adequately damped.

The reactor in conjunction with the Reactor Protective System is designed to accommodate safely and without fuel damage, the anticipated operational occurrences.

The reactor vessel and its closure head are fabricated from manganese molybdenum nickel steel internally clad with austenitic stainless steel. The vessel and its internals are designed so that the integrated neutron flux does not exceed ~~4.9~~6.56 x 10^{19} n/cm^2 (E > 1 Mev) over the ~~60~~ 80 year design life of the vessel.

Power excursions which could result from any credible reactivity addition do not cause damage, either by deformation or rupture of the reactor vessel and do not impair operation of the Engineered Safety Features.

The internal structures include the core support barrel, the lower support structure, the core shroud, the hold-down ring and the upper guide structure assembly. The core support barrel is a right circular cylinder supported from a ring flange from a ledge on the reactor vessel. The flange carries the entire weight of the core. The lower support structure transmits the weight of the core to the core support barrel by means of vertical columns and a beam structure. The core shroud surrounds the core and limits the amount of coolant bypass flow. The upper guide structure provides a flow shroud for the CEAs and prevents upward motion of the fuel assemblies during pressure transients. Lateral motion limiters or snubbers are provided at the lower end of the core support barrel assembly. The hold-down ring acts as a shim and is set between the reactor vessel head and the upper guide structure to resist axial upward movement.

Further details concerning the reactor are given in Chapters 3 and 4.

1.2.2.2 Reactor Coolant and Auxiliary Systems

The Reactor Coolant System is arranged as two closed loops connected in parallel to the reactor vessel. Each loop consists of one 42 in. ID outlet (hot) pipe, one steam generator, two 30 in. ID inlet (cold) pipes and two reactor coolant pumps. An electrically heated pressurizer is connected to the hot leg of one of the loops and a safety injection line is connected to each of the four cold legs.

The Reactor Coolant System operates at a nominal pressure of 2235 psig. The reactor coolant enters near the top of the reactor vessel, and flows downward between the reactor vessel shell and the core support barrel into the lower plenum. It then flows upward through the core, leaves the reactor vessel, and flows through the tube side of the two vertical U-tube steam generators where heat is transferred to the secondary system. Reactor coolant pumps return the reactor coolant to the reactor vessel.

2.5.2.7.1 Earthquake Frequency Analysis

The probability of a seismic event equaling or exceeding the OBE was computed using standard statistical methods. The region surrounding the site was subdivided into areas of similar seismicity (see Subsection 2.5.2.3 and Figure 2.5-32) and the statistical properties of seismic events were developed for each area. The effects of events in neighboring provinces were attenuated to the site. The annual probability of events of each intensity greater than or equal to V MM at the site was computed. Horizontal accelerations for each intensity were taken from the 1975 Trifunac-Brady relationship. The annual probability for an event greater than or equal to .05g was interpolated from the results of this computation, and the probability of occurrence of one or more such events was computed. The results of these computations indicated a probability of occurrence of this event of approximately 2 percent over the ~~60~~80-year life of the plant, or about once per 3,000 years.

2.5.3 SURFACE FAULTING

2.5.3.1 Geologic Conditions of the Site

The geologic conditions of the site and surrounding area have been described in the Subsections 2.5.1.1 and 2.5.1.2. Geologic structure and hypothesized faulting in the region have been discussed in Subsection 2.5.1.1.4. It is concluded that no seismic generative faults exist within 200 miles of the site. Figure 2.5-8 shows the locations of hypothesized faulting within peninsular Florida.

2.5.3.2 Evidence or Absence of Fault Offset

No specific detailed reports on the geology and groundwater resources of St. Lucie County have been published; however, geologic studies have been reported for Martin County to the south(2) and Indian River(1) and Brevard(39) Counties to the north. Figure 2.5-27 is a map showing all hypothesized structures in the three county area.

2.5.3.2.1 Hypothesized Faulting in Indian River County

Bermes(1) utilized data from wells drilled into Eocene strata to develop geologic sections in Indian River County. These sections indicated Eocene and Miocene strata sloped gently to the southeast in most of the county. Bermes reported an apparent change in dip from less than five feet per mile to greater than 70 feet per mile and the occurrence of Oligocene age beds near the eastern margin of the county. He postulates a somewhat complex system of three high-angle, normal faults essentially parallel to the coastline (see Figure 2.5-27) to explain the steepening dip and the occurrence and apparent thickening in Oligocene strata to the east. Strata on the east side of the faults were projected to be downthrown. The faults were postulated based on elevation differences of about 225 feet in the top of the Ocala group over a horizontal distance of about 2.5 miles. He did not discuss the age of the faulting, but the fault traces shown in his geologic sections terminated at the base of Miocene strata, indicating an age of last movement of at least 20 million years.

2.5.3.2.2 Hypothesized Faulting in St. Lucie and Martin Counties

Lichtler(2) utilized electric logs and cuttings from deep wells in a study of Martin County. Lichtler postulated a high angle northwesterly trending normal fault parallel to, and four to five miles inland of the present coastline. The strata on the east side of the fault were projected as being

As shown on Figure 3.8-6, each line consists of a double barrier concentric pipe from the sump up to the suction line isolation valve outside the containment. The penetration assembly is designed for the differential motion associated with the SSE.

e) Fuel Transfer Tube Penetration

A fuel transfer tube penetration (Type V) is provided to transport fuel rods between the refueling transfer canal and the spent fuel pool during refueling operations of the reactor. The penetration is shown on Figure 3.8-7 and consists of a 36 inch diameter stainless steel pipe installed inside a 48 inch pipe. The inner pipe acts as the transfer tube and is fitted with a double gasketed blind flange in the refueling canal and a standard gate valve in the spent fuel pool. This arrangement prevents leakage through the transfer tube in the event of an accident. The outer pipe is welded to the containment vessel and provision is made for testing welds essential to the integrity of containment. Bellows expansion joints are provided on the pipe to compensate for building settlement and differential seismic motion between the Reactor Building and the Fuel Handling Building.

The bellows expansion joints which form a part of the containment boundary meet the requirements of ASME Code, Section III. The fuel transfer tube bellows are designed for a 35 foot head of water.

Bellows design and construction is such that the bellows does not deflect more than its designed amount: The bellows is designed to withstand a ~~60~~80-year lifetime total of 7,000 cycles of expansion and compression due to operating thermal expansion and 200 cycles of differential settlement and seismic motion.

f) Containment Vacuum Breaker Penetration

The penetration consists of a nozzle welded on the containment vessel with a check valve inside the containment and a butterfly valve outside the containment (see Figure 9.4-9).

The containment vessel penetration details are shown on Figures 3.8-9, 3.8-10 and 3.811. Shield Building penetration details are shown on Figure 3.8-9.

3.8.2.1.1.2 Electrical Penetrations

Electrical penetrations are divided into the following three basic types with each performing a specific function:

a) Medium voltage penetrations (over 600 volts)

b) Low voltage power and control (600 volts and lower)

Test (T) - Test conditions are those tests in addition to the 10 hydrostatic or pneumatic tests[12] permitted by ASME Code, Section III, including leak tests or subsequent hydrostatic tests.

The appropriate loading combination and stress limits for each of the above conditions are discussed in Subsection 3.9.3.1.

In support of the design of each Quality Group A component, a fatigue analysis of the combined effects of mechanical and thermal loads is performed in accordance with the requirements of ASME Code, Section III. The purpose of the analysis is to demonstrate that fatigue failure does not occur when the components are subjected to typical dynamic events which may occur in the power plant.

The fatigue analysis is based upon a series of dynamic events depicted in the respective component specifications. Associated with each dynamic event is a mechanical, thermal-hydraulic transient presentation along with an assumed number of occurrences for the event. The presentation is generally simple and straightforward, since it is meant to envelop the actual plant response. The intent is to present material for purposes of design. A best-estimate representation of the expected plant dynamic response is neither intended nor appropriate. The fundamental concept is to ensure that the consequences of the normal and upset conditions which are expected to occur in the power plant are enveloped by one or more of the dynamic event portrayals in the component specifications. The number of occurrences selected for each dynamic event is considered to be conservative, so that in the aggregate a 80~~60~~-year useful life is provided by this design process.

A stress analysis is performed on Quality Group A piping in accordance with the ASME Code, Section III, 1971 edition and all addenda up to and including Summer 1973 addenda. A stress report is developed in accordance with Section NB of ASME Code, Section III. The Quality Group A piping is listed in Table 3.9-1 along with Group A Components.

The Quality Group A components listed in Table 3.9-1 are analyzed with the appropriate loading combinations of pressure, temperature and flow transients for the normal, upset, emergency, faulted and test conditions. Design load combinations and stress limits for the above components are given in Subsection 3.9.3.

Quality Group A piping is classified as seismic Category I and is analyzed as such. The operating basis earthquake (OBE) loading is considered to occur five times over the plant life with 40 cycles for each event. One safe shutdown earthquake (SSE) event is assumed to occur for Quality Group A piping for the life of the plant.

The ASME Quality Group A valves are designed in accordance with Article NB-3000 of ASME Code, Section III. The Quality Group A valves are as listed in Table 3.9-1. When required by ASME Code, Section III the Quality Group A valves are designed for the cyclic loading conditions shown in Table 3.9-2. The system transients for valves are supplied to the manufacturers. The manufacturers perform cyclic and transients analyses in accordance with the ASME Code. A stress report is submitted by each manufacturer to demonstrate that the requirements of Subarticle NB-3500 are satisfied.

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* Per EC 284419, no additional secondary-side hydrostatic tests are permitted on the 2B RSG. † Per EC 284513, no additional primary-side hydrostatic tests at the pressure/temperature conditions in Table 3.9-2 are permitted on the 2B RSG.

Subsection 3.9.3.1.1. The stress limits and loading combinations for NSSS Supplied Class 1, 2, and 3 components are described in Subsection 3.9.3.1.3.

ASME Code Class 2 and 3 components are designed for the concurrent loadings produced by pressure, deadweight, temperature distributions, the vibratory motion of the safe shutdown earthquake (SSE), and the dynamic system loadings associated with the appropriate plant faulted condition. The design loading combinations for specific plant operating conditions are listed in Table 3.9-5 and Table 3.9-5A for Group B & C Components and Piping respectively. Additionally, an investigation was performed for all Safety Class 2 and 3 piping systems (irrespective of operating temperature) to demonstrate that the number of equivalent thermal cycles, as defined in ASME Subsection NC 3611.2, was sufficiently low to confirm the conservatism of the existing stress analyses.

In accordance with the agreement reached at a meeting with the NRC and Florida Power & Light Company on October 14, 1982 an acceptance criteria of 1000 "Realistic" cycles was employed. In conducting this analysis, the following Safety Class 2 and 3 systems were reviewed:

Reactor Coolant	Component Cooling Water
Charging	Letdown
Safety Injection	Auxiliary Feedwater
Main Steam	Containment Spray
Main Feedwater	Intake Cooling Water

A sample calculation specifying methodology and a summary of the results is provided in Table 3.9-5b.

Using realistic values of cycle frequencies, all systems were shown to exhibit approximately 700 equivalent cycles. Using all the thermal transients that appear in the Safety Class 1 specification (Refer to Table 3.9-5b), which is conservative both in frequency and temperature variation, all systems were shown to have less than 1000 equivalent thermal cycles. Therefore, the above results confirm the conservatism of the existing stress analyses for Class 2 and 3 systems and was approved by the NRC (NUREG-0843 Supplement 3, April 1983).

Class 2 and 3 piping systems were reviewed for thermal fatigue and confirmed to be acceptable for ~~60~~80 years of operation. See Section ~~18.3.2.2~~19.3.3.2.

The specific criteria that provide the bases for design of a particular component are given in the specific sections that describe the corresponding fluid systems. The design pressure, temperature and other design transients that are considered in the design of each mechanical component are also listed.

The design rules and associated design stress limits applied to the design of ASME Code Class 2 and 3 components are in accordance with the ASME Code, Section III, Subsections NC and ND, respectively. In those areas of design where the applicable rules of Subsections NC and ND are not explicit, the rules are supplemented as described herein, and in Tables 3.9-6 and 3.9-7.

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TABLE 3.9-2

TRANSIENTS USED IN DESIGN AND FATIGUE ANALYSIS

NOTE: Class 1 piping and components were reviewed for thermal fatigue and were confirmed to be acceptable for a ~~60~~80 year design file, utilizing the original 40-year design cycles. See Section ~~18.3.2.1~~19.3.3.1.

1. Normal Conditions

(a) 500 heatup and cooldown cycles during the design life of the components with heating and cooling at a rate of 100°F/hr between 70°F and 532°F (653°F for the pressurizer). The heatup and cooldown rate of the system is administratively limited to 75°F/hr and 85°F/hr, respectively, to assure that these limits will not be exceeded. This is based on the original 40-year design life cycle and a normal plant cycle of one heatup and cooldown per month rounded to the next highest hundred. The heatup and cooldown cycles permitted on the 2B RSG were reduced from 500 to 120 per EC 284513.

(b) 15,000 power change cycles over the range of 15 percent to 100 percent of full load at 5 percent of full load per minute increasing and decreasing. This is based on a normal plant operation involving one cycle per day for 40 years rounded to the next highest 1000. (CEDM repairs implemented via PCM 03021 reduces the power change cycles from 15,000 to 2,000 cycles for the affected penetrations.) The power change cycles permitted on the 2B RSG were reduced from 15000 to 2000 per EC 284419.

(c) 2,000 cycles of step power changes of 10 percent of full load, increasing in the 15 percent to 90 percent of full load range and 2000 cycles decreasing in the 100 percent to 25 percent of full load range. This is based on the original 40-year design life cycle and a normal plant operation involving one cycle per week for 50 weeks of the year.

(d) The Reactor Vessel, Replacement Steam Generator and Reactor Coolant Pump are designed for 1 x 10^6 cycles of normal variations of ± 100 psi and ± 6°F when at operating temperature and pressure. The pressurizer normal design transient is 1 x 10^6 cycles of normal variations of ± 50 psi and ± 6°F. The 1 x 106 cycles is based on such a large value being equivalent to infinite cycles and thus the limiting stress is the endurance limit. The pressure and temperature variations are selected to be well within the actual fluctuations which are limited by control systems.

2. Upset Conditions

(a) 40 cycles of complete loss of reactor coolant flow when at 100 percent power. This is based on the original 40-year design life cycle and one reactor trip per year for the life of the plant resulting from failure of electrical supply to the reactor coolant pumps.

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TABLE 3.9-3B (Cont'd)

TRANSIENT		Transient Caterory	Reactor Vessel	Stm.Gen	Press	RC Pipe	Surge Line	Spray Line	R C Pump
8.	Chg. Noz.-Purification & Boron Dilution	NORMAL			24,000				
9.	Loss of Flow	UPSET	40	40	40	40	40	40	40
10.	Loss of Full Load	UPSET	40	40	40	40	40	40	40
11.	Reactor Trip/Loss of Load	UPSET	400	400	400	400	400	400	400
12.	Oper. Basis Earthquake	UPSET	200	200	200	200	200	200	200
13.	Loss of Charging	UPSET	N/A	N/A	N/A	20	N/A	N/A	N/A
14.	Loss of Letdown	UPSET	N/A	N/A	N/A	~~50~~500	N/A	N/A	N/A
15.	Loss of Secondary Pressure	EMERGENCY	5	5	5	5	5	5	5
16.	Safe Shutdown Earthquake + Normal Operation	FAULTED	1	1	1	1	1	1	1
17.	Safe Shutdown Earthquake + Normal Operation + Pipe Rupture	FAULTED	1	1	1	1	1	1	1
18.	Hydro Test (3110 psig)	TEST	10	10*	10	10	10	10	10
19.	Leak Test (2235 psig)	TEST	200	200*	200	200	200	200	200

* For the 2B RSG, the limits for these transients were reduced per EC 284513 as follows: Hydro Test reduced from 10 to 1; Leak Test reduced from 200 to 30.

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3.11.4 QUALIFICATION OF COMPONENTS

If the equipment in question meets the requirement found in Subsection 3.11.3, it must be qualified to 10 CFR 50.49. The "Environmental Qualification Report and Guidebook," Drawing 2998-A-451-1000 provides the information required to properly identify the environment to which the specific equipment must be qualified. Operability requirements associated with the component are discussed along with the required temperature, pressure, humidity, radiation, aging and submergence.

Each parameter is defined in a specific subsection. Most parameters are identified on Zone Maps as a convenient reference. Zone Maps indicate the normal and abnormal values associated with specific areas of the plant at a given period of time.

Harsh environments are characterized by abnormally high temperatures and pressures, high radiation doses, corrosive chemical spray, and/or high relative humidity. Also, in some cases, submergence may have to be considered based on equipment location with respect to the maximum flood level.

A mild environment, as defined in 10 CFR 50.49, is an environment that would at no time be significantly more severe than the environment which would occur during normal operation, including operational occurrences. Equipment located in a mild environment is not covered under10 CFR 50.49. Mild environments operability is assured by either: (a) periodic maintenance, inspection and/or a replacement program based on sound engineering judgement or manufacturer's recommendations; (b) a periodic testing program; (c) an equipment surveillance program.

Environments in which radiation is the only parameter of concern are considered to be mild if the total radiation dose (includes ~~60~~80-year normal dose plus the post accident dose) is 1.0E5 rads or less. This value is the threshold for evaluation and consideration. Excluded from this consideration, however, are most solid state electronic components and components that utilize teflon. Class 1E equipment located in environments between 1.0E3 and 1.0E5 are evaluated on a case by case basis.

For additional detail on the identification of environmental conditions refer to Drawing 2998-A-451-1000," Environmental Qualification Report and Guidebook."

3.11.5 MAINTENANCE

The purpose of the St. Lucie Unit 2 Equipment Qualification Program is the preservation of the qualification of safety related systems, structures and components. In order to accomplish the task, the plant has developed approved Design Control, Procurement and Maintenance Procedures. Each procedure has incorporated the requirements of environmental qualification according to the functional requirements of the program/system/component. The plants procedures are prepared to maintain proper design control, for plant modifications, procurement of new equipment and spare parts. The plants maintenance program is designed to provide preventative as well as corrective maintenance which is identified by field operational experience and industry correspondence. In addition, the component specific documentation package contains, in Section 5, the equipments qualified life. This qualification interval is developed based upon the vendors test report reviewed in conjunction with the environmental parameter associated with the area. After this review is completed a qualified life is established and operation with this piece of equipment up to the equipments end point is acceptable.

3.11.6 RECORDS/QUALITY ASSURANCE

A documentation package is prepared for the qualification of each manufacturers piece of equipment under the auspices of 10 CFR 50.49. This package contains the information, analysis and justifications necessary to demonstrate that the equipment is properly and validly qualified for the environmental effects of ~~60~~80 years of service plus a design basis accident.

This documentation package is developed from the criteria stipulated in the Environment Qualification Re port and Guidebook.

A complete listing of equipment under the auspices of 10 CFR 50.49 is maintained.

All three of the above documents are drawings and are developed and controlled under the procedures involving drawing preparation, updating and storage as specified in the FPL Quality Assurance Program.

The generic elements of the FPL Quality Assurance Program are described in the Florida Power and Light Quality Assurance Topical Report (QATR) discussed in Section 17.2. The QATR defines departmental responsibilities by which FPL implements the corporate Quality Assurance program.

3.11.7 CONCLUSIONS

The Equipment Qualifications Report and Guidebook, together with the manufacturers' specific Documentation Packages and the 10 CFR 50.49 list of equipment have been developed for the purpose of documenting the environmental qualification of safety related equipment. This program has insured the systems selected for qualification are complete, the environmental conditions resulting from the design basis accident are indentified and that the methods used for qualification are appropriate.

Based on these checks and the ongoing environmental qualification program, St. Lucie Unit 2 is in compliance with 10 CFR 50.49.

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4.3.2.7.5.2 Features Provided for Axial Xenon Effects and Power Distribution Effect and Control

a. RCS boration / dilution for control of the axial power distribution, if required
b. CEAs for additional axial power distribution control, if required.
c. RCS temperature for control of axial power distribution, if required.
d. Monitoring and accounting for the axial power distribution in the RPS.

4.3.2.8 Vessel Irradiation

The design of the reactor internals and of the water annulus between the active core and vessel wall is such that for reactor operation at the full power rating and an ~~80~~ approximate 90 percent capacity factor over the ~~60~~80-year design life of the vessel (or ~~48~~72 EFPY), the vessel fluence ~~greater than one MeV~~ at the vessel wall will reach approximately ~~3.8~~6.56 x 10^{19} n/cm^2 (>1 MeV). The 80-year SLR fluence projections include a 10 percent factor of conservatism for future cycles beyond the end-of-cycle 25 (Reference 79).~~The calculated exposure projections beyond the end-of-cycle 19 includes a 10 percent uncertainty factor.~~

The maximum fast neutron fluences greater than one MeV accumulated on the vessel clad base metal interface (CBMI) and shroud inside surface are as shown in Table 4.3-10. The projection fluxes are based on a time averaged equilibrium cycle radial power distribution and an axial power distribution with a peak to average of 1.11. The calculation assumed a thermal power of 2700 MWt for cycles 1 through 19 and of 3020 MWt for cycle 20 and onwards. The models used in these calculations are discussed in Subsection 4.3.3.3.

4.3.3 ANALYTICAL METHODS

Discussions of methodologies within this section are written from an historic perspective and may have been superseded by newer methods as discussed in Reference 65.

Westinghouse physics methodology is used to generate physics inputs and characteristics based on Reference 69 (beginning with Cycle 12) and Reference 70 (beginning with Cycle 15).

Starting with Cycle 23, AREVA methods are also approved for use in generating physics inputs and characteristics based on References 76, 77, and 78.

4.3.3.1 Reactivity and Power Distribution

4.3.3.1.1 Method of Analysis (HISTORICAL)

The nuclear design analysis for low enrichment PWR cores is based on a combination of multigroup neutron spectrum calculations, which provide cross sections appropriately averaged over a few broad energy groups, and few group one, two, and three dimensional diffusion theory calculations of integral and differential reactivity effects and power distributions. The multigroup calculations include spatial effects in those portions of the neutron energy spectrum where volume homogenization is inappropriate; e.g., the thermal neutron energy range. Most of the calculations are performed with the aid of computer programs embodying analytical procedures and fundamental nuclear data consistent with the current state of the art.

Comparisons between calculated and measured data that validate the design procedures are presented in Subsection 4.3.3.1.2. As improvements in analytical procedures are developed,

69. WCAP-11596-P-A, “Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurizer Water Reactors,” June 1988.

70. WCAP-10216-P-A, Rev. 1A, “Relaxation of Constant Axial Offset Control: FQ Surveillance Technical Specification,” February 1994.

71. WCAP-11397-P-A, “Revised Thermal Design Procedure,” April 1989.

72. Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” U.S. Nuclear Regulatory Commission, March 2001.

73. RSICC Code Package PSR-145, “FERRET: Least-Squares Solution to Nuclear Data and Reactor Physics Problems,” Radiation Safety Information Computational Center, Oak Ridge National Laboratory, January 1980.

74. RSIC Data Library Collection DLC-178, “SNLRML: Recommended Dosimetry Cross-Section Compendium,” Radiation Safety Information Computational Center, Oak Ridge National Laboratory, July 1994.

75. WCAP-16083-NP-A, Revision 0, “Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry,” May 2006.

76. EMF-96-029(P)(A), Volumes 1 and 2, "Reactor Analysis System for PWRs, Volume 1 Methodology Description, Volume 2 Benchmarking Results."

77. XN-NF-78-44(NP)(A), "A Generic Analysis of the Control Rod Ejection Transient for Pressurized Water Reactors."

78. XN-75-27(A) and Supplements 1 through 5, "Exxon Nuclear Neutronics Design Methods for Pressurized Water Reactors", Exxon Nuclear Company, Report and Supplement 1 dated April 1977, Supplement 2 dated December 1980, Supplement 3 dated September 1981 (P), Supplement 4 dated December 1986 (P), and Supplement 5 dated February 1987 (P).

79. WCAP-18609-NP Rev 2, “St. Lucie Units 1 & 2 Subsequent License Renewal: Time Limiting Aging Analysis on Reactor Vessel Integrity”, July 2021

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~~TABLE 4.3-10~~

~~MAXIMUM FAST FLUENCE GREATER THAN 1 MeV (n/cm²)~~

~~Cycles~~	~~Cumulative EFPY~~	~~Fluence, Shroud Inside Surface~~	~~Fluence, Vessel CBMI~~
~~1~~	~~1.05~~	~~1.68E+21*~~	~~1.10E+18~~
~~2~~	~~2.17~~	~~3.35E+21~~	~~2.22E+18~~
~~3~~	~~3.40~~	~~5.12E+21~~	~~3.36E+18~~
~~4~~	~~4.55~~	~~6.78E+21~~	~~4.09E+18~~
~~5~~	~~5.84~~	~~8.64E+21~~	~~4.88E+18~~
~~6~~	~~7.19~~	~~1.02E+22~~	~~5.76E+18~~
~~7~~	~~8.40~~	~~1.16E+22~~	~~6.62E+18~~
~~8~~	~~9.78~~	~~1.28E+22~~	~~7.19E+18~~
~~9~~	~~11.01~~	~~1.42E+22~~	~~7.88E+18~~
~~10~~	~~12.46~~	~~1.59E+22~~	~~8.73E+18~~
~~11~~	~~13.77~~	~~1.74E+22~~	~~9.50E+18~~
~~12~~	~~15.29~~	~~1.88E+22~~	~~1.04E+19~~
~~13~~	~~16.58~~	~~2.03E+22~~	~~1.12E+19~~
~~14~~	~~18.01~~	~~2.18E+22~~	~~1.21E+19~~
~~15~~	~~19.16~~	~~2.30E+22~~	~~1.28E+19~~
~~16~~	~~20.41~~	~~2.43E+22~~	~~1.37E+19~~
~~17~~	~~21.73~~	~~2.57E+22~~	~~1.45E+19~~
~~18~~	~~23.14~~	~~2.72E+22~~	~~1.54E+19~~
~~19~~	~~24.46~~	~~2.86E+22~~	~~1.63E+19~~
~~20~~	~~25.87~~	~~3.04E+22~~	~~1.75E+19~~
~~21~~	~~27.28~~	~~3.24E+22~~	~~1.88E+19~~
~~22~~	~~28.69~~	~~3.44E+22~~	~~2.01E+19~~
~~--~~	~~32.00~~	~~3.90E+22~~	~~2.31E+19~~
~~--~~	~~36.00~~	~~4.47E+22~~	~~2.67E+19~~
~~--~~	~~40.00~~	~~5.03E+22~~	~~3.03E+19~~
~~--~~	~~48.00~~	~~6.16E+22~~	~~3.76E+19~~
~~--~~	~~54.00~~	~~7.01E+22~~	~~4.31E+19~~
~~--~~	~~60.00~~	~~7.85E+22~~	~~4.85E+19~~

~~Note: * denotes powers of ten, i.e., 1.68 x 10^21~~

T4.3-12 Amendment No. ~~24 (09/17)~~Later

LTOP transients have not been analyzed for the simultaneous startup of more than one reactor coolant pump (RCP). Such operation is procedurally precluded since the operator starts only one RCP at a time and a second RCP is not started until system pressure is stabilized. RCP motor amperage is used to establish nominal pump performance and operation prior to starting a second RCP. Additionally, there is an LTOP transient alarm that indicates that a pressure transient is occurring.

A Technical Specification requires that the operator not start an RCP if the ΔT exceeds 40°F. However, administrative procedures will ensure that the ΔT is maintained below 30°F. A separate Technical Specification ensures that the appropriate action is taken if one PORV or one SDCS relief valve is out of service during the LTOP mode of operation.

An analysis of P/T limits and LTOP protection for the period ending at 55 EFPY was performed. The LTOP enable temperatures were determined by following the guidance of the ASME Boiler and Pressure Vessel Code Section XI, Appendix G. They were calculated to be less than or equal to 246°F during heatup and less than or equal to 224°F during cooldown. Since the 55 EFPY pressure-temperature limits are less restrictive than the 21.7 EFPY limits, the PORV setpoint was raised to 490 psia from 470 psia for increased operational flexibility. A change to the SDCRV setpoint of 350 psia was not practical or required.

The P/T limits, LTOP requirements, setpoints and controls were evaluated for operation at EPU conditions. The only update for EPU conditions was a reduction in the period of applicability to approximately 47 EFPY from 55 EFPY. Per Reference 7, a further reduction in the period of applicability from 47 EFPY to 31.98 EFPY was updated. Per Reference 8, the period of applicability was extended from 31.98 EFPY to 55 EFPY.

5.2.6.2.2 Provision for Low Temperature Overpressure Protection

During heatup, RCS pressure is maintained below the PORV pressure setpoints until after the PORVs are re-set to the "normal" high setpoint. The PORVs can be re-set to the normal setpoint when cold leg temperature increases above the maximum temperature for LTOP during heatup (nominally Tc = 246°F), defined in the Technical Specifications.

During cooldown, RCS pressure is decreased to below the PORV low pressure setpoint before cooling the plant to below the maximum temperature for LTOP during cooldown (nominally Tc = 224°F), defined in the Technical Specifications. Once temperature is lowered, the PORV control switch must be aligned in the LTOP mode.

The LTOP mode applies for all temperatures within the maximum LTOP temperature range. The PORVs will remain in the LTOP mode until the RCS is opened during refueling. The LTOP system is designed to be aligned during all heatup and cooldown operations.

5.2.6.3 Equipment Parameters

Each PORV is actuated from a 90-40v dc solenoid valve which is energized automatically from a pressurizer pressure transmitter. Each PORV is designed to close on interruption of power to the solenoid valve.

Pertinent PORV operational and design requirements are presented in Table 5.4-9. The PORVs are sized based on a transient (simultaneous operation of two HPSI pumps and three charging pumps) initiated from a water-solid condition. The analysis of the Subsection 5.2.6.2.1 limiting transients for the period ending 55 EFPY demonstrated that the PORV water relieving capacity is

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Section 5.2: REFERENCES

1) Letter, A. C. Thadani (NRC) to C. O. Woody (FPL), "Relief from Parts of ASME Code Section XI," dated January 13, 1986.

2) Letter, A. C. Thadani (NRC) to C. O. Woody (FPL), "Relief from Parts of ASME Code Section XI," dated October 10, 1986.

3) Letter, H. N. Berkow (NRC) to J. H. Goldberg (FPL), "St. Lucie Unit 2 - Reliefs from Parts of ASME Code Section XI," dated October 2, 1989.

4) Letter, Eugene V. Imbro (NRC) to Thomas F. Plunkett (FPL), "St. Lucie Units 1 and 2 - Request for Approval of ASME Code Case N-416-1 As An Alternative to the Required Hydrostatic Pressure Test," dated April 29, 1996.

5) Safety Assessment by Plant Systems Branch Division of Systems Safety and Analysis Office of Nuclear Reactor Regulation Region II Concerns (TIA 96-019) Regarding the Containment Radiation Monitoring Systems at St. Lucie Units 1 and 2, and Turkey Point Units 3 and 4, May 27, 1999.

6) Calculation PSL-2FJI-99-001, “Steam Generator Blowdown Radiation Monitor Response Time."

7) PSL-ENG-SESJ-16-005, "Proposed License Amendment for Changing the RCS Pressure/Temperature Limits and LTOP Requirements from 47 to 31.98 EFPY," Rev. 0 [EC-287453 Rev. 0]

8) Letter, Natreon J. Jordan (NRC) to Don Moul (FPL), “St. Lucie Plant, Unit No. 2 – Issuance of Amendment No. 206 to Replace the Current Time-Limited Reactor Coolant System Pressure/Temperature Limit Curves and LTOP Setpoints with Curves and Setpoints That Will Remain in Effective for 55 Effective Full Power Years (EPID L-2020-LLA-0029) dated February 26, 2021 ADAMS Accession No. ML21022A219

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TABLE 5.3-9

CAPSULE ASSEMBLY REMOVAL SCHEDULE(d)

~~Location on~~ Vessel Location~~Wall~~	~~Approximate Removal~~Capsule ~~Schedule~~ Withdrawal (EFPY) (d)	~~Predicted~~ Capsule Fluence (n/cm^2, E > 1.0 MeV) Factor(~~c~~b)	Lead Factor(~~c~~b)
83°(a)	1.11	~~1.40~~ 1.42 x 10^{18}	1.~~30~~27
~~97~~263°(a)	~~25.55(a)~~11.07	~~2.25~~ 1.02 x 10^{19}	1.~~30~~ 26
~~104~~97°(a)	~~Standby (b)~~25.55	~~---~~2.29 x 10^{19}	~~0.98~~1.28
~~263~~277°	~~11.07(a)~~ 61	~~1.00~~ 6.56 x 10^{19}	1.~~29~~ 27
~~277~~104°	Standby (e)~~44/(EOL)(b)~~	---~~4.5 x 10^{19}~~	~~1.30~~0.92
284°	Standby (~~b~~e)	---	0.~~98~~ 92

Note:

(a)~~.~~ Numbers for these capsules are actual. Fluence values reflect the most recent analysis.~~Actual removal time (Reference 7).~~

~~b. As required by ASTM E185, one standby capsule will be removed at the end of license fluence and available for testing.~~

~~c~~(b)~~.~~ Lead Factor is defined as the capsule fluence~~/~~ divided by RV base metal peak fluence ~~(Reference 7)~~

~~d~~(c)~~.~~ Capsule removal schedule changes required NRC approval per 10 CFR 50, Appendix H.

(d) For capsules not yet withdrawn, the capsule will be withdrawn at the outage nearest to but following the stated EFPY.

(e) Capsule will reach the EOLE fluence of 4.80 x 10^{19} n/cm^2 at 62 EFPY.

The warmed air passes through an orifice plate and then enters the electric heater section where it is heated to approximately 1150°F to 1400°F causing recombination to occur. The flow then enters the cooling/exhausting section where the stream is mixed and diluted with cooler containment air in order to discharge the stream back into the containment atmosphere at a lower temperature.

Each hydrogen recombiner system has a removal capacity which is sufficient to limit concentrations of gases within the containment to safe concentrations; i.e., concentrations below the flammability limits. After a three hour startup period, the recombiner efficiency is 99100 percent and the effluent does not exceed 100°F above ambient.

The unit is manufactured primarily of corrosion-resistant, high-temperature material for major structural components, except for the base which is steel. The electric hydrogen recombiner used conventional type electric resistance heaters sheathed with Incoloy-800 which is an excellent corrosion resistant material for this service. These heaters are designed to operate with sheath temperatures equal to those used in certain commercial heaters; however, these recombiner heaters operate at significantly lower power densities than in commercial practice.

The recombiners are located on the elevation 62.0 feet of the containment. They are inaccessible following a LOCA, and as such there is no sharing of recombiners among St. Lucie Units 1 and 2 or with other facilities. The hydrogen recombiners are designed for ~~60 years~~ ~~normal and~~ one year post LOCA conditions. Design and performance data for the recombiners are listed in Table 6.2-55.

Each of the two recombiners is 100 percent capacity, and is connected to a separate onsite power source so that no single failure results in a total loss of recombiner function.

The recombiner is started by the operator by manual action from the control room. The operator is alerted when the containment H2 level reaches three volume percent as signaled by the redundant Class 1E alarms of the Containment Hydrogen Analyzer System. Plant procedures provide guidance to the operator on when to start the hydrogen recombiner following a LOCA.

6.2.5.2.3 Containment Hydrogen Purge System

The Continuous Containment Purge/Hydrogen Purge System is provided as a further possible means of controlling hydrogen inside the containment following a LOCA. This system is provided as required by the NRC, although no single failure following a LOCA would necessitate its use. Therefore, the system is non-safety-related except for the containment penetrations and isolation valves which are seismic Category I and Quality Group B. See Table 6.2-57 for a failure mode and effects analysis.

The only redundancy required in the system is to assure the containment isolation function, as discussed in Subsection 6.2.4. Functional and operational redundancy of the system is not provided, as the system serves only as a diverse means of backup to the already redundant containment hydrogen recombiners. However, the system is capable of controlling hydrogen inside containment following a LOCA independent of the operation of recombiners. Table 6.2-56 shows the design data and materials for hydrogen purge system.

The system consists of a purge makeup penetration line, an exhaust penetration line, two exhaust fans and interconnecting ductwork between the fan discharge and suction header of the Shield Building Ventilation System (see Figure 9.4-11).

APPENDIX B

AGING MANAGEMENT PROGRAMS

PSL 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 AMPs 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 PSL plant programs whenever possible. However, some existing PSL programs aligned with multiple NUREG-2191 AMPs, and some NUREG-2191 AMPs aligned with multiple PSL programs, therefore the existing PSL AMPs to be continued for SLR will be renamed as applicable to align with the NUREG-2191 AMP names. New PSL AMPs align with the NUREG-2191 AMP names. All existing PSL 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.

Certain current PSL 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. The existing AMPs, as well as the new AMPs, are listed in Table B-1 and Table B-2.

Consistent with the discussion above, the following new programs will be created at PSL for the purposes of SLR:

- PSL One-Time Inspection AMP (Section B.2.3.20)
- PSL Selective Leaching AMP (Section B.2.3.21),

- PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP (Section B.2.3.24),
- PSL Buried and Underground Piping and Tanks AMP (Section B.2.3.27),
- PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section B.2.3.28),
- PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits AMP (Section B.2.3.37),
- PSL Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (Section B.2.3.38),
- PSL Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (Section B.2.3.39),
- PSL Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (Section B.2.3.40),
- PSL Metal Enclosed Bus AMP (Section B.2.3.41),
- PSL Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (Section B.2.3.42), and
- PSL High-Voltage Insulators AMP (Section B.2.3.43).

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:

- PSL Reactor Head Closure Stud Bolting AMP (Section B.2.3.3),
- PSL Outdoor and Large Atmospheric Metallic Storage Tank AMP (Section B.2.3.17),
- PSL Fuel Oil Chemistry AMP (Section B.2.3.18),
- PSL Reactor Vessel Material Surveillance AMP (Section B.2.3.19),
- PSL ASME Section XI, Subsection IWF AMP (Section B.2.3.30), and
- PSL Structures Monitoring AMP (Section B.2.3.33)

B.1.2 <u>Method of Discussion</u>

For those PSL 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 PSL 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 PSL 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 FPL Quality Assurance (QA) Program for PSL 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 SR and NNS SSCs and commodity groups that are included within the scope of the AMPs. Generically, the three elements are applicable as follows.

<u>Corrective Actions:</u>

The PSL Corrective Action Program (CAP) is applied regardless of the safety classification of the SSC or commodity group. The PSL 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 conditions are corrected through the Work Control Process in accordance with plant procedures. The PSL CAP specifies that for equipment conditions 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 PSL 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 PSL 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 PSL CAP provides for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure effective corrective actions are taken. The PSL 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 SR and NNS 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 PSL 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 PSL aging management programs and activities.

Administrative Controls:

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 PSL 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 <u>Operating Experience</u>

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 PSL OE program. The PSL OE program (part of the NEE fleet OE program) meets the requirements of NUREG-0737 (Reference 1.6.19), "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff." The PSL OE program also meets the requirements of NEI 14-12 (Reference 1.6.20), "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 PSL 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 NextEra fleet, PSL Units 1 and 2 receive OE (internal and external to FPL) 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.

OE involving age-related degradation is tracked and trended such that adverse trends are entered into the corrective action program for evaluation. OE 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. PSL meets the requirements of NEI 14-13 (Reference 1.6.21) 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. PSL 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 areas for improvement related to the effectiveness of the current PSL license renewal AMPs in accordance with NEI 14-12 “Aging Management Program Effectiveness”. The assessment was completed in January 2021 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 criterion that was not met, was identified as a finding. The finding for each element for a particular AMP were evaluated comprehensively to determine if the combined findings 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 findings could have prevented the proper implementation of the associated element. Elements were not considered to be failed if the finding 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 findings. OE was also updated as applicable.

A recent internal OE review identified several findings associated with 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 PSL 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 PSL, in conjunction with the PSL CAP, has proven to be effective in learning from adverse conditions and events, and improving programs that address age-related degradation.

In addition, for multi-unit sites where sample size is not based on their percentage of the population and the inspections are conducted periodically (not one-time inspections), reduced inspections for several aging management programs are acceptable. In order to conduct the reduced number of inspections, operating conditions at each unit must be demonstrated to be similar enough to provide representative inspection results. Based on the following, the units and operating experience at PSL are similar such that a reduced number of inspections can be credited:

- PSL Units 1 and 2 were both approved for extended power uprate in 2012.
- Operating experience has not indicated a trend of out-of-spec water chemistry conditions that would differentiate one unit from the other. Action Request (AR) keyword searches “water chem,” “MIC,” “micro,” “amoni,” “dezinc,” and “de-zinc” yield no plant operating experience that indicates long term or repeated out-of-spec water chemistry conditions.
- The Atlantic Ocean is the source for raw water systems at PSL with no differences between the units.
- Per the PSL Technical Specifications, the emergency diesel generators are tested at the same frequency.
- Treated water systems common to both units have the same chemistry requirements and operate at similar temperatures

B.1.5 Aging Management Programs

Table B-1 lists the PSL 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 PSL. Existing AMPs are based on either an existing LR AMP or existing plant program. Additionally, Table B-2 lists the PSL 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 PSL 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	N/A	Concrete Containment Unbonded Tendon Prestress (PSL U1 and U2 containments do not have prestressed tendons.)	N/A
X.E1	B.2.2.3	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 (PSL U1 and U2 are PWRs.)	N/A
XI.M7	N/A	BWR Stress Corrosion Cracking (PSL U1 and U2 are PWRs.)	N/A
XI.M8	N/A	BWR Penetrations (PSL U1 and U2 are PWRs.)	N/A
XI.M9	N/A	BWR Vessel Internals (PSL U1 and U2 are PWRs.)	N/A
XI.M10	B.2.3.4	Boric Acid Corrosion	Existing
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	Existing
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 (PSL 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 and Light Load (Related to Refueling) Handling Systems	Existing
XI.M24	B.2.3.14	Compressed Air Monitoring	Existing
XI.M25	N/A	BWR Reactor Water Cleanup System	N/A

Table B-1
List of PSL Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
		(PSL U1 and U2 are PWRs.)	
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	New
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	N/A	Flux Thimble Tube Inspection (PSL U1 and U2 do not use bottom mounted moveable flux thimble tubes.)	N/A
XI.M38	B.2.3.24	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	New
XI.M39	B.2.3.25	Lubricating Oil Analysis	Existing
XI.M40	B.2.3.26	Monitoring of Neutron-Absorbing Materials Other Than Boraflex	Existing
XI.M41	B.2.3.27	Buried and Underground Piping and Tanks	New
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	N/A	ASME Section XI, Subsection IWL (PSL U1 and U2 do not have any components within this program scope.)	N/A
XI.S3	B.2.3.30	ASME Section XI, Subsection IWF	Existing
XI.S4	B.2.3.31	10 CFR Part 50, Appendix J	Existing
XI.S5	B.2.3.32	Masonry Walls	Existing
XI.S6	B.2.3.33	Structures Monitoring	Existing
XI.S7	B.2.3.34	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Existing
XI.S8	B.2.3.35	Protective Coating Monitoring and Maintenance	Existing
XI.E1	B.2.3.36	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Existing
XI.E2	B.2.3.37	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits	New
XI.E3A	B.2.3.38	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New
XI.E3B	B.2.3.39	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New

Table B-1
List of PSL Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
XI.E3C	B.2.3.40	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New
XI.E4	B.2.3.41	Metal Enclosed Bus	New
XI.E5	N/A	Fuse Holders (PSL U1 and U2 do not have any components within this program scope.)	N/A
XI.E6	B.2.3.42	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New
XI.E7	B.2.3.43	High-Voltage Insulators	New
N/A	B.2.3.44	Pressurizer Surge Line	Existing

Table B-2
Aging Management Programs

PSL Aging Management Program	Section	NUREG-2191 Section
10 CFR Part 50, Appendix J	B.2.3.31	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.2.3.30	XI.S3
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
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 Environmental Qualification Requirements	B.2.3.42	XI.E6
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.36	XI.E1
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits	B.2.3.37	XI.E2
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.39	XI.E3B
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.40	XI.E3C
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.38	XI.E3A
Environmental Qualification of Electric Equipment	B.2.2.3	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
Fuel Oil Chemistry	B.2.3.18	XI.M30
High-Voltage Insulators	B.2.3.43	XI.E7
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B.2.3.24	XI.M38

Table B-2
Aging Management Programs

PSL Aging Management Program	Section	NUREG-2191 Section
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B.2.3.13	XI.M23
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B.2.3.34	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.2.3.25	XI.M39
Masonry Walls	B.2.3.32	XI.S5
Metal Enclosed Bus	B.2.3.41	XI.E4
Monitoring of Neutron-Absorbing Materials Other Than Boraflex	B.2.3.26	XI.M40
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
Pressurizer Surge Line	B.2.3.44	N/A
Protective Coating Monitoring and Maintenance	B.2.3.35	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.2.3.33	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 PSL AMPs is shown below. Links to the sections describing the PSL NUREG-2191 programs are provided.

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	PSL 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	Not Applicable (PSL U1 and U2 containments do not have prestressed tendons.)
X.E1	Environmental Qualification of Electric Equipment	Environmental Qualification of Electric Equipment (Section B.2.2.3)
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 (PSL U1 and U2 are PWRs)
XI.M7	BWR Stress Corrosion Cracking	Not Applicable (PSL U1 and U2 are PWRs)
XI.M8	BWR Penetrations	Not Applicable (PSL U1 and U2 are PWRs)
XI.M9	BWR Vessel Internals	Not Applicable (PSL 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 (PSL 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	PSL Aging Management Program
XI.M23	Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) 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 (PSL 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	Not Applicable (PSL U1 and U2 do not use bottom mounted moveable flux thimble tubes.)
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.3.24)
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis (Section B.2.3.25)
XI.M40	Monitoring of Neutron-Absorbing Materials Other Than Boraflex	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (Section B.2.3.26)
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	Not Applicable (PSL U1 and U2 do not have any components within this program scope.)
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF (Section B.2.3.30)
XI.S4	10 CFR Part 50, Appendix J	10 CFR 50, Appendix J (Section B.2.3.31)
XI.S5	Masonry Walls	Masonry Walls (Section B.2.3.32)
XI.S6	Structures Monitoring	Structures Monitoring (Section B.2.3.33)
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section B.2.3.34)

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	PSL Aging Management Program
XI.S8	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance (Section B.2.3.35)
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 Environmental Qualification Requirements (Section B.2.3.36)
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 Environmental Qualification Requirements used in Instrumentation Circuits (Section B.2.3.37)
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 Environmental Qualification Requirements (Section B.2.3.38)
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 Environmental Qualification Requirements (Section B.2.3.39)
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 Environmental Qualification Requirements (Section B.2.3.40)
XI.E4	Metal Enclosed Bus	Metal Enclosed Bus (Section B.2.3.41)
XI.E5	Fuse Holders	Not Applicable (PSL 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 Environmental Qualification Requirements (Section B.2.3.42)
XI.E7	High-Voltage Insulators	High-Voltage Insulators (Section B.2.3.43)
N/A	Pressurizer Surge Line	Pressurizer Surge Line (Section B.2.3.44)

Table B-4
PSL Aging Management Program Consistency with NUREG-2191

PSL Aging Management Program	Section	PSL 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
Environmental Qualification of Electric Equipment	B.2.2.3	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	No
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	No	No
Reactor Vessel Internals	B.2.3.7	No	XI.M16A	Yes	No
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	No	No
Open-Cycle Cooling Water System	B.2.3.11	No	XI.M20	Yes	No
Closed Treated Water Systems	B.2.3.12	No	XI.M21A	Yes	No
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B.2.3.13	No	XI.M23	Yes	No
Compressed Air Monitoring	B.2.3.14	No	XI.M24	Yes	No

Table B-4
PSL Aging Management Program Consistency with NUREG-2191

PSL Aging Management Program	Section	PSL Plant-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
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	Yes
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	New	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	No	No
External Surfaces Monitoring of Mechanical Components	B.2.3.23	No	XI.M36	Yes	No
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B.2.3.24	No	XI.M38	New	No
Lubricating Oil Analysis	B.2.3.25	No	XI.M39	Yes	No
Monitoring of Neutron-Absorbing Materials Other Than Boraflex	B.2.3.26	No	XI.M40	Yes	No
Buried and Underground Piping and Tanks	B.2.3.27	No	XI.M41	New	No
Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B.2.3.28	No	XI.M42	New	No
ASME Section XI, Subsection IWE	B.2.3.29	No	XI.S1	Yes	No
ASME Section XI, Subsection IWF	B.2.3.30	No	XI.S3	Yes	Yes
10 CFR Part 50, Appendix J	B.2.3.31	No	XI.S4	No	No
Masonry Walls	B.2.3.32	No	XI.S5	Yes	No
Structures Monitoring	B.2.3.33	No	XI.S6	Yes	Yes

Table B-4
PSL Aging Management Program Consistency with NUREG-2191

PSL Aging Management Program	Section	PSL Plant-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B.2.3.34	No	XI.S7	Yes	No
Protective Coating Monitoring and Maintenance	B.2.3.35	No	XI.S8	Yes	No
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.36	No	XI.E1	Yes	No
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits	B.2.3.37	No	XI.E2	New	No
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.38	No	XI.E3A	New	No
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.39	No	XI.E3B	New	No

Table B-4
PSL Aging Management Program Consistency with NUREG-2191

PSL Aging Management Program	Section	PSL Plant-Specific?	NUREG-2191 Comparison		
			NUREG-2191 Section	Enhancements?	Exceptions?
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.40	No	XI.E3C	New	No
Metal Enclosed Bus	B.2.3.41	No	XI.E4	New	No
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.42	No	XI.E6	New	No
High-Voltage Insulators	B.2.3.43	No	XI.E7	New	No
Pressurizer Surge Line	B.2.3.44	Yes	N/A	No	No

B.2.2. NUREG-2191 Chapter X Aging Management Programs

This section provides summaries of the NUREG-2191 Chapter X AMPs associated with TLAAs at PSL.

B.2.2.1 Fatigue Monitoring

Program Description

The PSL Fatigue Monitoring AMP is an existing AMP that provides an acceptable basis for managing fatigue of components that are the subject of 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 PSL Fatigue Monitoring AMP verifies the continued acceptability of existing analyses through manual cycle counting for monitoring CUFs for the selected component locations using cycle based fatigue monitoring. PSL does not use a computer software package or an on-line fatigue monitoring program to demonstrate the ability of components with a calculated CUF to withstand the cyclic loads associated with plant transient operations.

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 4.3.1 provides details of the evaluation of fatigue for PSL Class 1 components that have a calculated CUF. As shown in SLRA Tables 4.3.1-1 through 4.3.1-6, with the exception of the loss of letdown flow transient, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. Tables 4.3.1-5 and 4.3.1-6 show that the 80-year project cycles for the loss of letdown flow transient remains below the new limit of 500 cycles. The affected component Class 1 fatigue analyses have been updated to incorporate the new cycle limit of 500 for the loss of letdown flow transient and the component CUF values are acceptable. Therefore, all Class 1 component CUF values remain less than 1.0 for the SPEO.

CUF_{en} is CUF adjusted to account for the effects of the reactor water environment on component fatigue life. For PSL 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 PSL site-specific NUREG/CR-6260 (Reference ML031480219) locations, have been evaluated for EAF. SLRA Section 4.3.3 provides details of the evaluation for environmentally assisted fatigue for the PSL SPEO. The effects of fatigue on the intended functions of the ASME Code, Section III components piping components listed in Table 4.3.3-1 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.

The PSL Fatigue Monitoring AMP provides for corrective actions when any actual transient cycle count comes within 80 percent of 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. 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 PSL Fatigue Monitoring AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section X.M1, "Fatigue Monitoring."

Exceptions to NUREG-2191

None.

Enhancements

The PSL Fatigue Monitoring 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
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 PSL Water Chemistry (Section B.2.3.2) 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.
3. Parameters Monitored or Inspected	Update the plant procedure to monitor and track the loss of letdown flow transient during the SPEO.
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

Element Affected	Enhancement
	assumed quantities, transient definitions have changed, unanticipated new fatigue loading events are discovered, or the geometries of components are modified.
6. Acceptance Criteria	Update the AMP governing procedure to add an additional acceptance criterion associated with HELB CUF criteria. (Unit 2 only)

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

- 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, Revision 1. The methodology described in NUREG/CR-6909, Revision 1 was utilized in calculating the PSL F_{en}s 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. PSL has not used this simplified methodology to calculate fatigue usage.

- 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 came up 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 manual cycle counting performed at PSL, and software such as FatiguePro is not used.

The examples above demonstrate that the PSL Fatigue Monitoring AMP reviews OE 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

In 2015, a foreign object event in the 2B Steam Generator hotleg required re-evaluation for continued operation. One of the required actions from the evaluation was to add torque cycles of the 2B replacement steam generator (RSG) primary manway. This change shows that internal OE is tracked and appropriately updates the PSL Fatigue Monitoring program.

Program Assessments and Evaluations

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and one administrative issue related to the PSL Fatigue Monitoring AMP was identified and has since been resolved.

The PSL 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 PSL Fatigue Monitoring AMP, with enhancements, provides 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.2.2.2 Neutron Fluence Monitoring

Program Description

The PSL Neutron Fluence Monitoring AMP, previously the fluence and uncertainty calculation portion of the PSL Reactor Vessel Material Surveillance (Section B.2.3.19) AMP, is an existing AMP that provides 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 PSL Reactor Vessel Material Surveillance AMP (Section B.2.3.19).

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.”

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" (Reference ML010890301). 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 WCAP-18124-NP-A methodology, which complies with RG 1.190, is used for PSL fluence determinations in the cylindrical RPV region that surrounds the effective height of the active fuel (the RPV beltline) and for materials that were not originally considered to be part of the beltline region but have projected fluence values greater than 1 x 10^{17} n/cm^2 (E > 1 MeV) at the end of the SLR period (extended beltline). 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. 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.

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-18124-NP-A methodology or similar methodology was also used to estimate conservative neutron fluence for the RPV locations above and below the effective height of the active fuel for SLR. PSL 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, PSL 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-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 PSL Neutron Fluence Monitoring AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section X.M2, “Neutron Fluence Monitoring” as modified by SLR-ISG-2021-02-Mechanical, “Updated Aging

Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance."

Exceptions to NUREG-2191

None.

Enhancements

The PSL Neutron Fluence Monitoring 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
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 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 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 TLAA to 80 years in the additional justification of RPV fluence in regions other than the active fuel region.

Operating Experience

<u>Industry Operating Experience</u>

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

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 1×10^{17} n/cm^2 at the end of license/life (Reference ML16081A333).

RPV nozzle fluence was also addressed for original license renewal. PSL 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

- 2016 – Unit 1 Post-Approval Site Inspection for License Renewal, Inspection Report

  The NRC completed a post-approval site inspection for License Renewal for Unit 1. Based on the inspection sample selected for review, no findings, or violations of more than minor significance were identified. The inspectors determined that PSL fully established the required aging management programs (AMPs), and time-limited aging analyses to manage the aging effects of in-scope structures, systems, and components (SSCs) through the PEO of Unit 1, with the exception of an Unresolved Item (URI) associated with the implementation status of the various commitment items that required follow-up during future license renewal inspections to obtain reasonable assurance that the license renewal commitments are met, and that the aging effects of affected SSCs would be managed during the PEO.

  The inspectors identified a follow-up item for the initial license renewal commitment 17, “Reactor Vessel Integrity Program.” The inspectors noted that PSL credited the fleet procedure to meet the regulatory commitment associated with the integration of all four reactor vessel integrity subprograms into a single program document. The fleet procedure required a plant-specific procedure be developed for each site describing the important parameters needed to meet the regulatory requirements specific to that station. The inspectors noted that the plant-specific procedure for Unit 1 was still under development with a target completion date of March 1, 2016. The revision was issued in February 2016.

- 2017 – Unit 2 Post-Approval Site Inspection for License Renewal, Inspection Report

  The NRC completed a post-approval site inspection for License Renewal for Unit 2. Based on the sample selected for review, the inspector determined that commitments, license conditions, and regulatory requirements associated with the renewed facility operating license were met. The inspector also determined that the licensee had administrative controls in place to ensure completion of pending actions scheduled both prior to and during the PEO.

  At the time of the inspection, PSL was in the process of revising the Reactor Vessel P-T limit curves in response to the material testing results of the most recent surveillance capsule. The P-T limit curves have since been submitted to and approved by the NRC to support 60 years of operation.

Program Assessments and Evaluations

- 2018 – Reactor Vessel Integrity Program Roles and Responsibilities Review

  The 2018 Strategic Initiatives for Engineering include actions to ensure Engineering Programs have alignment with other organizations. As part of this initiative, a Level 1 Assessment (L1A) was performed to ensure the roles and responsibilities for implementing the Reactor Vessel Integrity Program across the fleet were clearly understood and accurately reflected in program procedures. Roles and responsibilities in fleet and site procedures that implement the Reactor Vessel Integrity Program were reviewed. The following items were identified:

  1. Programs engineering versus fuels department responsibilities as identified in fleet procedure required updates.

  2. There is no consistent documentation for cumulative EFPY determination.

  The following actions addressed the items:

  The fleet procedure was revised to clarify department responsibilities and consistent methods for documentation of EFPY and fluence calculations.

  A review of fluence calculations pertaining to the RV-Integrity Program and/or RV-Internals Program was performed to ensure they were maintained as controlled calculations, as applicable.

- 2020 – License Renewal Effectiveness Review and SLR Interview Track

  AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021, and no findings related to the PSL Neutron Fluence Monitoring AMP were identified.

The PSL 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 PSL Neutron Fluence Monitoring AMP, with enhancements, provides 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.2.2.3 Environmental Qualification of Electric Equipment

Program Description

The PSL Environmental Qualification of Electric Equipment AMP is an existing AMP, previously the 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 in-service (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 PSL and fleet organization to provide reasonable assurance of 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 provide reasonable assurance that the equipment remains qualified. The PSL Environmental Qualification 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 period of extended operation (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 PSL Environmental Qualification documentation packages (referred to as EQ Doc Pacs) are considered time-limited aging analyses (TLAAs) per 10 CFR 54.21(c)(1).

NUREG-2191 Consistency

The PSL Environmental Qualification of Electric Equipment AMP, with enhancement, will be consistent without to exception the 10 elements of NUREG-2191, Section X.E1, “Environmental Qualification of Electric Equipment.”

Exceptions to NUREG-2191

None.

Enhancements

The PSL Environmental Qualification of Electric Equipment 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	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

<u>Industry Operating Experience</u>

Industry OE on Environmental Qualification covers a long period of time, dating back to the 1970s. Every nuclear plant has an Environmental Qualification 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. There is an EQ program owner assigned to each site. This individual receives and addresses (if necessary) the industry OE on EQ (from other plants, from NRC, and from external industry guidance, such as NUGEQ) and also addresses 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 Environmental Qualification Programs to reflect the new plant lifetime of 60 years. PSL completed this effort shortly after receiving its renewed license, around 2003. 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 PSL 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 PSL Environmental Qualification of Electric Equipment (Section B.2.2.3) AMP is highlighted in PSL EQ implementing procedure.

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

Plant Specific Operating Experience

The following examples of OE provide objective evidence that the PSL Environmental Qualification of Electric Equipment (Section B.2.2.3) AMP will be effective in providing reasonable assurance 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 Environmental Qualification Program health report is currently GREEN and has shown green for several quarters.

A search of the AR database in the corrective action program (CAP) for EQ related issues discovered the following:

- In April of 2016, an initial NRC EQ pilot inspection identified weaknesses in addressing industry notice (IN 97-45) regarding the very low amperage metering and its sensitivity to Containment High Range Radiation Monitor (CHRRM) accuracy due to thermally induced currents (TIC) during design basis accident conditions. This resulted in replacement of the CHRRMS cable and installation of new mineral insulated (MI) cable that would not be susceptible to the postulated accident extreme conditions.

- In April of 2016, during an NRC inspection, a Unit 1 EQ Doc Pac for a power operated relief valve (PORV) flow element did not correctly specify the qualified life based on the most limiting component. Further investigation determined that this was strictly a documentation issue. There was no challenge to the EQ requirements and the Doc Pac was revised.

- In March of 2020, Emerson Process Management provided a Part 21 notification related to the treatment of temperature rise due to electronics self-heating in qualified life thermal aging calculations for Models 1153 and 1154. After considerable industry and utility involvement, Rosemount issued and the NRC reviewed a method for calculating qualified life taking the internal temperature rise into account. PSL used this information to determine that the scheduled EQ component replacement due dates were not impacted by the Part 21 notification. PSL has also taken action by qualifying replacement Rosemount 3150 series transmitters at the site to replace all EQ transmitters through a 5-outage period plan.

- In July of 2017, a one-time due date extension for an EQ PM activity to replace a limit switch on Unit 2 was requested. An evaluation was performed by the fleet EQ engineer and a qualified life was determined. Using the appropriate calculations and tracking methods, the due date extension was allowed for replacement of the limit switch at the next available Unit 2 outage.

  The above examples demonstrate that the Environmental Qualification Program is informed and enhanced due to the review of plant specific OE

- In June of 2016 during an EQ Component Design Basis Inspection (CDBI), inspectors identified three examples of green non-cited violations of 10 CFR Part 50.49.e.(5) for failure to ensure conformance with the qualification procedures and methods specified in IEEE 323-1974. These examples involved a variety of EQ Doc Pac issues on Namco limit switches, Limitorque actuators, tape splice material, Target Rock solenoids, and high-range radiation monitors. The files needed to be updated to address the following: non-thermal aging items, validation of quality level (QL) input information, various electrical sub-components not previously addressed, and EQ procedure updates. An operability determination confirmed these components to be operable and the issues were entered into the corrective action program. This AR was prepared to capture the NRC violation in CAP and address the requisite evaluation via an Apparent Cause Evaluation (ACE), which was performed and corrective action was completed. An extent-of-condition review was also performed.

  This AR shows that the Environmental Qualification Program is responsive to regulatory review and input, and that corrective actions are taken when weaknesses are identified.

- In December of 2014, during a review of an engineering change, the possibility that Unit 1 had exceeded the EQ thermal life of the coils associated with the MSIV solenoid valves was discovered. Work order (WO) reviews determined that the solenoid coils were not replaced during the last outage, meaning they did not meet the requirements of the EQ documentation. Engineering conducted reviews and an evaluation demonstrated that the previous calculations were conservative thus providing additional margin. Through investigation and additional calculations engineering concluded that the installed solenoid coils were qualified to the start of the next outage.

This AR shows that the Environmental Qualification Program is capable of implementing investigations and corrective actions when issues with EQ components or documentation are discovered.

Program Assessments and Evaluations

In April of 2019, using the guidance in NEI 14-12, a review of the effectiveness of PSL AMPs was performed to identify any findings and ensure appropriate actions were taken to rectify the findings. With regard to the Environmental Qualification Program, the following administrative item was identified:

The EQ AMP identified an EQ Limitorque motor operated valve (MOV) actuator PM procedure as an implementing document. However, the procedure was superseded, and no information was located indicating the Environmental Qualification Program owner had reviewed this change. An AR was issued to re-instate the superseded procedure or provide a basis for an alternative procedure to be used. This AR was administrative in nature and did not adversely impact the installed equipment EQ qualification.

In conclusion, the EQ AMP was judged to be effective and no findings were identified.

In 2015 and 2017, the NRC examined activities conducted under PSL'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 program basis documents and calculations, and discussed these with licensee personnel to verify that the TLAAs were addressed as described in the LRA, and the corresponding NRC SER. Based on the review of the timeliness and adequacy of PSL's actions, the NRC concluded that the Environmental Qualification Program commitments were met

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and some findings related to the PSL EQ AMP were identified. The findings were administrative in nature and are being addressed under the PSL CAP.

The PSL Environmental Qualification of Electric Equipment 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 PSL 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 function(s) of 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 and any plant-specific AMPs credited for managing the effects of aging at PSL.

B.2.3.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Program Description

The PSL ASME Section XI Inservice Inspection (ISI), Subsections IWB, IWC, and IWD AMP is an existing AMP 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 for both Units 1 and 2 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 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP includes Class 1, 2 and 3 pressure-retaining components, and their integral attachments, including welds, and pressure-retaining bolting. The following aging effects are managed by this AMP: loss of material, cracking, loss of preload, reduction in fracture toughness, and loss of mechanical closure integrity. Periodic visual, surface, and volumetric examinations, as well as leakage tests are utilized for inspection and testing of in-scope components. These inspections allow for identification and assessment of age-related degradation, as well as establishment of corrective actions.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD 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, IWC-2411 and Table IWC-2411-1, IWD-2411 and Table IWD-2411-1, as well as the 5th Interval ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (ISI Program document) for Unit 1 and the 4th Interval ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (ISI Program document) for Unit 2.

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 PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP, currently based on the PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP documents. Examinations are performed as specified to identify the overall condition of components and to provide reasonable assurance that any degraded conditions identified are corrected prior to returning the component to service. The PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP documents are 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 PSL 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.

NUREG-2191 Consistency

The PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP is consistent without exception to 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

None.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

- IN 2005-02 (NRC Event 41048): Pressure Boundary Leakage at Steam Generator Bowl Drain Welds. This was evaluated for PSL under an AR and determined that PSL Units 1 and 2 do not contain pressure boundary drain nozzles in the steam generator bowls; however, the PSL Unit 2 steam generator did have eight instrument nozzles in the cold leg bowls made of alloy 600 material. These Unit 2 alloy 600 nozzles were replaced with alloy 690 as part of the steam generator replacement in 2007. The Unit 1 replacement steam generator already had incorporated alloy 690 instrument cold leg nozzles.

- IN 2006-27 (NSAL-06-8), Circumferential Cracking in the Stainless Steel Pressurizer Heater Sleeves of Pressurized Water Reactors. Since this issue is only applicable to pressurizer heater sleeves made of SS and PSL pressurizer heater sleeves are alloy 690 (Unit 1) and alloy 600 (Unit 2), there is no impact to PSL Units 1 or 2.

- IN 2014-02, Failure to Properly Pressure Test Reactor Vessel Flange Leak-Off Lines. A PSL Operations training module was revised to discuss IN 2014-02.

Plant Specific Operating Experience

- Owners Activity Reports (OARs) were reviewed over the last five years (2015-2020). There were no flaws identified nor any other significant issues reported during this time period.

Program Assessments and Evaluations

- A self-assessment was completed in February 2015 to review and provide the tracking mechanism of all License Commitments, as well as ensuring that they were captured in the UFSAR prior to the PEO.

- A post-approval site inspection for License Renewal for Unit 1 was performed by the NRC in 2016. Based on the inspection sample selected for review, no findings, or violations of more than minor significance were identified. The inspectors determined that PSL fully established the required aging management programs (AMPs), and time-limited aging analyses to manage the aging effects of in-scope structures, systems, and components (SSCs) through the PEO of Unit 1, with the exception of an Unresolved Item (URI) associated with the implementation status of the various commitment items that required follow-up during future license renewal inspections to obtain reasonable assurance that the license renewal commitments are met, and that the aging effects of affected SSCs would be managed during the PEO. Of the identified affected commitment items for the URI, one was related to the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP. For Commitment 20, Environmentally Assisted Fatigue of the Pressurizer Surge Line, the proposed program for managing environmentally assisted fatigue of the pressurizer surge line was submitted to the NRC on October 29, 2015. The inspectors noted that the proposal detailed the intent of the licensee to utilize the ASME Code, ASME Section XI ISI Program to manage the recurring inspections, and the associated evaluations for any flaws noted. At the time of this inspection, no SER had yet been issued. This item and the URI were resolved were resolved via issuance of the SER, which included this Commitment 20 for Unit 1.

- A post-approval site inspection for License Renewal for Unit 2 was performed by the NRC in 2017. Based on the sample selected for review, the inspector determined that commitments, license conditions, and regulatory requirements associated with the renewed facility operating license were met. The inspector also determined that the licensee had administrative controls in place to ensure completion of pending actions scheduled both prior to and during the PEO.

- AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP were identified.

The PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD 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 PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP provides 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.2.3.2 Water Chemistry

Program Description

The PSL Water Chemistry AMP, previously known as the Water Chemistry Control Program - Water Chemistry Subprogram, 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 PSL Water Chemistry AMP relies on monitoring and control of reactor water chemistry based on industry guidelines contained in EPRI 3002000505 (Reference 1.6.22), "PWR Primary Water Chemistry Guidelines," and EPRI 3002010645 (Reference 1.6.23), "PWR Secondary Water Chemistry Guidelines."

The PSL 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 PSL 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 PSL 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.

The PSL 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, additional samples 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 PSL Water Chemistry AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.M2, “Water Chemistry” as modified by SLR-ISG-2021-02-Mechanical, Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The PSL 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 OE 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. ARs 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.

Industry Operating Experience

- 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 is primarily measured at the final feed water sample point. Low ECP values are indicative of a non-corrosive, reducing environment. PSL feed water hydrazine concentration is administratively kept at a minimum of 8 times the dissolved oxygen concentration of the system component with a significant volume upstream of the steam generators or 20 ppb, whichever is higher.

- Carbohydrazide is added as a metal passivator and an oxygen scavenger. Experimental and industry data has shown that carbohydrazide 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 carbohydrazide than hydrazine. For PSL, carbohydrazide may be used instead of or in addition to hydrazine. The normal value and initiate action thresholds apply to the oxygen scavenger equivalent concentration.

Plant Specific Operating Experience

The status of the PSL Water Chemistry Program is tracked and trended via quarterly program health reports. A review of the quarterly program health reports for 2015 through 2020 determined that the PSL Water Chemistry AMP has been green from 2017 through 2020. Prior program health reports identified outstanding WOs and an outstanding condition of certification. These items were corrected, and no repeat incidents were found.

- OE has not indicated a trend of out-of-spec water chemistry conditions that would differentiate one Unit from the other. AR keyword searches “water chem,” “MIC,” “micro,” “ammoni,” “dezinc,” and “de-zinc” yield no plant OE that indicates long-term or repeated out-of-spec water chemistry conditions.

- In 2017, the Unit 1 spent fuel pool (SFP) ion exchanger (IX) showed signs of exhaustion, and the SFP contaminants showed an increasing trend on chloride and sulfate. As a result, the PSL Water Chemistry implementing document was updated to perform anion analysis on weekly basis on the Unit 1 SFP. In 2019, the Unit 1 SFP anion was identified to have 113 ppb sulfate which was above the limit due to ion exchanger exhaustion. As a result, the SFP IX was isolated and kept isolated until replaced.

- In 2020, weekly sampling of the Unit 2 SFP identified above limit sulfate concentration. The Unit 2 IX was identified to be elevated in sulfate concentration due to purification ion exchanger exhaustion in 2019. The Unit 2 SFP IX was replaced per work order.

- In 2017, Unit 2 steam generator deposit characterization was performed following an outage. The steam generator deposit samples collected from the water lance system filters consisted predominately of fine black powder, and no tube scale or hard collar fragments were identified. The bulk powder samples after steam generator replacement showed slightly increased nickel concentrations over those samples obtained prior to the steam generator replacement in 2007. No deviations or adverse conditions were identified by this deposit characterization that warrant documentation in the corrective action program. No changes to the secondary water chemistry program were warranted based on the findings of this deposit characterization.

- In 2018, Unit 1 steam generator deposit characterization was performed following an outage. The steam generator deposit samples collected from the water lance system filters consisted predominately of fine black powder, and very small quantities of tube scale and debris/foreign material were found. The elemental concentrations of the bulk powder were relatively uniform between the two steam generators. The bulk powder samples after steam generator replacement showed slightly increased Ni concentrations over those samples obtained prior to the steam generator replacement in 2007. No deviations or adverse conditions were identified by this deposit characterization that warrant documentation in the corrective action program. No changes to the secondary water chemistry program were warranted based on the findings of this deposit characterization.

- In 2017, comprehensive hideout return studies for Unit 1 and Unit 2 steam generators were performed during their respective refueling outages. Minimal quantities of impurity returns were observed for both Units which suggested a lack of significant impurity hideout in the steam generators during normal operations. The quantities of the total cumulative returns of all species were similar or less than those during the previous outage except for aluminum in Unit 1. Cumulative aluminum return was more than expected. The condenser tubesheets are made of aluminum bronze and so are a potential source of aluminum. The higher aluminum return could also be attributable to maintenance activities performed during the cycle such as paints, abrasives, gasket material and elastomers. No deviations or adverse conditions were identified by the hideout return studies, and no changes to the secondary water chemistry program were warranted based on the hideout return studies.

<u>Program Assessments and Evaluations</u>

- In November 2010, a self-assessment was performed to identify areas that were not completed for PSL LR commitments. There were no commitments regarding the Chemistry Control Program, and no findings were identified.

- In 2015, a quick hit self-assessment (QHSA) of steady-state cycle chemistry trends for Cycle 25 was performed. All chemistry parameters for which a target value was specified met the respective target value for Cycle 25. Cycle ammonia was higher than desired and contributed to blowdown demineralizer exhaustion. However, the value was monitored, and no adverse conditions were identified during the assessment that warranted documentation in the CAP.

- In 2016, a QHSA was performed to identify gaps between the station Secondary Water Chemistry program and the EPRI Secondary Water

Chemistry Guideline, Revision 7, and relevant industry standards for secondary water chemistry programs. The PSL Water Chemistry AMP implementing document was updated per the guideline as the result of the QHSA, and no unexpected gaps were found.

- In 2017, Revision 8 of the EPRI Secondary Water Chemistry Guideline was issued. A detailed analysis was performed to review the secondary chemistry program documents against the changes incorporated into Revision 8 of the EPRI Guideline. The PSL Water Chemistry AMP implementing document was revised in accordance with Revision 8 of the EPRI Guideline in 2018.

- In November 2015, The NRC completed a post-approval site inspection for License Renewal for Unit 1 in accordance with NRC Inspection Procedure (IP) 71003. Based on the inspection sample selected for review, no findings were identified regarding the PSL Water Chemistry AMP. The inspectors determined that PSL fully established the required AMPs, and time-limited aging analyses to manage the aging effects of in-scope SSCs through the PEO of Unit 1.

- In October 2017, the NRC completed a Post-Approval Site Inspection for License Renewal for Unit 2 in accordance with NRC IP71003. The NRC inspectors did not identify any findings regarding the PSL Water Chemistry AMP and determined that aging management activities were consistent with licensing basis documents and program procedures.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in January 2021 and some findings related to the PSL Water Chemistry AMP were identified. The review determined administrative actions to include additional chemistry program implementing procedures and Preventive Maintenance Requirements (PMRQs) in the License Renewal Basis Document. An enhancement was made for additional personnel to become qualified to the plant's Aging Management Program Owner mentor guide.

The PSL Water 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 PSL Water Chemistry AMP provides 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.2.3.3 Reactor Head Closure Stud Bolting

Program Description

The PSL Reactor Head Closure Stud Bolting AMP is an existing AMP for subsequent license renewal (SLR), related to and currently part of the ASME Section XI, Subsection IWB, portion of the PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1). This PSL Reactor Head Closure Stud Bolting AMP provides (a) in-service 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 PSL Reactor Head Closure Stud Bolting AMP is in accordance with the regulatory position delineated in NRC RG 1.65 ((Reference 1.6.24), "Materials and Inspections for Reactor Vessel Closure Studs." The scope of this AMP includes:

a. Reactor vessel closure studs
b. Reactor vessel closure head nuts
c. Reactor vessel threads in flange
d. Reactor vessel closure washers and bushings

Through inspections performed as part of the PSL ASME Section XI Inservice Inspection, 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, in place	Volumetric or Surface
	B6.40	Threads in Flange	Volumetric
	B6.50	Closure Washers, Bushings	VT-1 Visual

This PSL Reactor Head Closure Stud Bolting 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 (ultrasonic) 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 PSL ISI Program Plans. 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. Surface examination indicates the presence of surface discontinuities and flaws. Volumetric examination indicates the presence of discontinuities or flaws throughout the volume of material. The extent and frequency of inspections is specified in Table IWB-2500-1, as modified in accordance with the PSL ISI Program Plans.

Appropriate preventive measures have been used for the reactor head closure stud bolting based on site OE and best practices.

This PSL Reactor Head Closure Stud Bolting 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 PSL ISI Program Plans and will be continued throughout the SPEO.

The acceptance criteria associated with this AMP, provided in the PSL ISI Program Plans, 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-3400 and IWB-3500. When areas of degradation are identified, an engineering evaluation is performed in accordance with IWB-3100 to determine if the component is acceptable for continued service, or if repair or replacement is required in accordance with Subsections IWB-3600, 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 will be included in the PSL Reactor Head Closure Stud Bolting AMP, for completeness, prior to entering the SPEO.

NUREG-2191 Consistency

The PSL Reactor Head Closure Stud Bolting AMP, with enhancements, will be consistent with exceptions to the 10 elements of NUREG-2191, Section XI.M3, “Reactor Head Closure Stud Bolting”.

Exceptions to NUREG-2191

The PSL Reactor Head Closure Stud Bolting AMP includes the following exceptions to the NUREG-2191 guidance:

1. 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. PSL reactor head closure stud bolting is considered high-strength steel, and PSL is taking exception to Element 2(d), Preventive Actions. The exception is acceptable because PSL 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 less than 150 ksi and a maximum tensile strength of 170 ksi.

2. For Element 4, Detection of Aging Effects, relief for the Unit 1 Fifth 10-Year ISI Interval and Unit 2 Fourth 10-Year ISI Interval has been requested from the schedule of reactor pressure vessel (RPV) bolting examinations specified in ASME Section XI Code, Table IWB-2500-1, Category B-G-1, and IWB-2420, in order to accommodate an additional set of reactor vessel

closure studs, nuts, and washers that are shared between PSL Units 1 and 2 in rotation. Use of three sets of reactor vessel closure studs, nuts, and washers does not make it feasible to maintain an inspection cycle which meets the requirements of successive examinations per ASME Section XI, IWB-2420(a). Note that PSL Units 1 and 2 were granted similar relief for the Fourth and Third 10-Year ISI Intervals respectively.

3. 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 actual measured yield strength less than 1,034 megapascals (MPa) (150 kilo-pounds per square inch (ksi)) for newly installed studs. Existing warehouse spares would be required to meet this NUREG-2191 recommendation and there is insufficient information available to make that determination. Therefore, PSL is taking an exception to Element 7, Corrective Actions. The exception is acceptable because PSL 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 less than 150 ksi and a maximum tensile strength of 170 ksi.

Enhancements

The PSL Reactor Head Closure Stud Bolting 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	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 and a maximum tensile strength of 170 ksi. In addition, revise maintenance procedures to preclude the use of molybdenum disulfide (MoS_2) lubricant for the reactor head closure stud bolting.
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 and a maximum tensile strength of 170 ksi.

Operating Experience

Industry Operating Experience

PSL 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 Cycle 26 RFO in the spring of 2012, 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 in the Cycle 26 RFO.

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 flooded with cavity water which could lead to boric acid corrosion (the remaining three holes, which had guide studs inserted, 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 for Surry Power Station to replace the failed ones, using a design similar to the (effective) plugs used at North Anna Power Station. No subsequent OE 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 OE above was reviewed and no changes were required to the PSL Reactor Head Closure Stud Bolting AMP. PSL reviews industry OE and incorporates applicable industry OE into the AMP when required. This ensures that the program will continue to be effective during the SPEO.

Plant Specific Operating Experience

A search of CRs/ARs on reactor head closure stud bolting for both PSL Units 1 and 2 revealed that no degradation of the studs or nuts has been detected. The only issue found at PSL for reactor head closure stud bolting was that the Unit 1 reactor vessel closure head flange stud #49 would not thread into the vessel flange; however, after repeated cleaning of the flange hole stud #49 was able to be threaded into the reactor vessel flange. This issue occurred in 2013 and there have been no further re-occurrences.

Program Assessments and Evaluations

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Reactor Head Closure Stud Bolting AMP were identified.

The PSL 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, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The PSL Reactor Head Closure Stud Bolting AMP, with enhancements and exceptions, 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 PSL 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 1.6.25), as documented in FPL letter L-88-244 (Reference ML17222A278), 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 PSL 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 PSL 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 PSL Boric Acid Corrosion AMP covers any susceptible systems, structures, and components (SSC) 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 PSL 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

PSL Corrective Action Program. Detected boric acid crystal buildup or deposits are cleaned per engineering evaluation. Per the NRC GL 88-05 recommendation, an objective of the PSL 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 PSL 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 PSL 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 revised no later than six months prior to entering the SPEO, as discussed below.

NUREG-2191 Consistency

The PSL Boric Acid Corrosion AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M10, “Boric Acid Corrosion”.

Exceptions to NUREG-2191

None.

Enhancements

The PSL Boric Acid Corrosion AMP will be enhanced as follows, for alignment with NUREG-2191, Section XI.M10. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Include other potential means to help in the identification of borated water leakage, such as the following in order to identify potential borated water leaks inside containment that have not been detected during walkdowns and maintenance: a. Airborne radioactivity monitoring b. Humidity monitoring (for trending increases in humidity levels due to unidentified RCS leakage) c. Temperature monitoring (for trending increases in room/area temperatures due to unidentified RCS leakage) d. Containment air cooler thermal performance monitoring (for corroborating increases in containment atmosphere temperature or humidity with decreases in cooler efficiency due to boric acid plate out)

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Include a requirement in the PSL Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components AMP implementing documents to document evidence of boric acid residue (plating out of moist steam) inside containment cooler housings or similar locations such as cooling unit drain pans and to enter evidence in to the corrective action program to be evaluated under a boric acid corrosion control (BACC) program evaluation.

Operating Experience

Industry Operating Experience

PSL 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:

- PSL response to NRC Bulletin 2002-001, "Response to NRC Bulletin 2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity, Letter No. NRC 2002-061 (Reference ML090300540) included a description and evaluation of PSL's inspection program that concluded the PSL 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. In response to the bulletin, FPL informed NRC that the bulletin is not applicable to PSL Unit 1 and Unit 2 since they do not have penetrations in the lower head of the reactor pressure vessel in Letter L-2003-234 , “Response to NRC Bulletin 2003-02, Leakage from Reactor Pressure Vessel Lower Head Penetration and Reactor Coolant Pressure Boundary Integrity” (Reference ML032671199)

- 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 PSL. PSL has 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. PSL is making an enhancement to coordinate with the PSL Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components AMP regarding evidence of boric acid residue (plating out of moist steam) inside containment cooler housings or similar locations such as cooling unit drain pans.

Plant Specific Operating Experience

The PSL Boric Acid Corrosion AMP is a mature, established program.

A large percentage of the work orders (WOs) and CRs/ARs 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 WOs initiated to repair and/or investigate evidence of borated water leakage were a result of performing system walkdowns during pressure testing. Program health reports show the PSL Boric Acid Corrosion AMP status to be Green as of November 2020. Ongoing actions include the scheduling of WOs to correct boric acid leakage. Boric acid leakage WOs are coded with the Boric Acid Corrosion Control (BACC) attribute and the license renewal attribute and are prioritized for completion by a BACC site team. With timely condition screening and evaluation, the significance and total number of boric acid leakage conditions are trended to ensure the program health remains green. Quarterly license renewal self-assessments, performed by the site program owner, review new BACC WOs and assign actions for any unscheduled WOs.

A recent instance of a through wall boric acid leak was identified on the PSL Unit 2 Boric Acid Makeup pump casing in 2019. The coordinator identified that the boric acid deposit had returned in the area where he had marked the casing. The Boric Acid Leak Screening form was not completed prior to the initial cleaning as required per BACC Program. The leak was repaired. Additionally, Program Engineering took an action to review the fleet BACC program to ensure that proper oversight and programmatic controls are in place to mitigate through wall leaks based on the recent trend identified at PSL.

Previous work management deferrals of scheduled boric acid leak repairs resulted in an increasing backlog trend that was identified in 2017. The issue was escalated, and the leak repairs were completed without further rescheduling.

The PSL Boric Acid Corrosion AMP procedures were updated to implement Revision 2 of WCAP-15988-NP (Reference ML041190170). The update also implemented various enhancements including guidance for intermittent, active leakage to be treated as active leakage, and clarified guidance for suspect or confirmed pressure-boundary leakage to ensure timely entry into CAP.

Program Assessments and Evaluations

In 2010, a self-assessment was performed to identify areas that were not completed for the PSL License Renewal (LR) commitments. There were no findings related to the PSL Boric Acid Corrosion AMP and no license renewal commitments were changed since the SER was issued.

In 2015, a focused self-assessment was performed to identify actions required to achieve readiness for the NRC License Renewal Implementation IP71003 Phase II

Inspection. The review also included verification that licensing activities associated with the renewed operating licenses were being met and to determine readiness for the subsequent IP71003 Phase I and II inspection. There were no findings identified.

In 2017, this self-assessment focused on the readiness for the NRC License Renewal Implementation IP71003 Phase II inspections. The assessment determined that License Renewal implementation was on track but identified some items that needed to be closed prior to the August 28, 2017 NRC Phase II inspection. Resolution of the items were tracked and resolved through the corrective action program.

In September 2019, an interim effectiveness review and assessment (~2 year) on Elements 4, 7 and 10 of the PSL Boric Acid Corrosion AMP was performed and there were no findings.

The PSL Boric Acid Corrosion AMP was evaluated as part of Unit 1 and Unit 2 post-approval site inspections for License Renewal conducted by the NRC in accordance with NRC IP71003. The inspection verified that programs and associated enhancements were in place. Based on review of adequacy of the licensee actions, PSL was determined to have met the required commitments for the PSL Boric Acid Corrosion AMP.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and some findings related to the PSL Boric Acid Corrosion AMP were identified. The review determined that two PMRQs for the containment BACC walkdowns are to be added to the PSL Boric Acid Corrosion AMP implementing procedure.

The PSL 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 PSL Boric Acid Corrosion 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.2.3.5 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

Program Description

The PSL 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 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. In 2005, the PSL Unit 1 pressurizer was replaced with a new, like-for-like pressurizer, with Alloy 690 material replacing all components previously composed of Alloy 600. In 2005 and 2007, for PSL Units 1 and 2, reactor pressure vessel (RPV) closure heads with Alloy 600 control element drive mechanism (CEDM) penetrations were replaced by new heads with CEDM penetrations made with more resistant Alloy 690 material. Future inspections of the new reactor vessel heads are in accordance with ASME Code Case N-729 which has been included in the site augmented in-service inspection program including the conditions listed in 10 CFR 50.55a. PSL will continue to monitor industry programs to ensure that PWSCC is managed for the SPEO. This AMP is used in conjunction with the following PSL 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 (Section B.2.3.1) and Boric Acid Corrosion AMP (Section B.2.3.4), respectively.

The reactor coolant system leak rate associated with inventory balancing is calculated frequently, as required by PSL Technical Specifications, Section 3/4.4.6, 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 PSL 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 for PSL Unit 1 and 4th Interval Inservice Inspection Plan for PSL Unit 2, lists current inspection requirements for nickel alloy components at PSL.

NUREG-2191 Consistency

The PSL 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 without exception to 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.”

Exceptions to NUREG-2191

None.

Enhancements

The PSL 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 enhancement is to be implemented no later than 6 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 alloy 600 material 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

<u>Industry Operating Experience</u>

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

Industry OE and information from NSSS vendors is evaluated for effect on inspection requirements. Industry OE includes:

- IN 2005-02 (NRC Event 41048): Pressure Boundary Leakage at Steam Generator Bowl Drain Welds. This NRC event was evaluated for PSL under an AR. PSL Units 1 and 2 do not contain pressure boundary drain nozzles in the steam generator bowls. However, the PSL Unit 2 steam generator did at the time have eight instrument nozzles in the cold leg bowls that were made of alloy 600 material. These nozzles were already identified and were part of the boric acid walkdown visual inspections in each refueling outage (with insulation in place). Since these were cold leg nozzles, they were of lower susceptibility than the hot leg temperature Catawba Unit 2 nozzles. However, they were added to the next Unit 2 refueling outage for bare metal visual inspection. These Unit 2 alloy 600 nozzles were replaced with alloy 690 as part of the steam generator replacement in 2007. The Unit 1 replacement steam generators already had incorporated alloy 690 instrument cold leg nozzles in the design.

- IN 2006-27 (NSAL-06-8), Circumferential Cracking in the Stainless Steel Pressurizer Heater Sleeves of Pressurized Water Reactors. This issue is only applicable to pressurizer heater sleeves made of SS. PSL pressurizer heater sleeves are alloy 690 (Unit 1) and alloy 600 (Unit 2). These nickel-based materials are not subject to the same SCC mechanisms as the SS pressurizer heater sleeve penetrations; therefore, there were no implications or impact to PSL Units 1 or 2.

- 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. PSL follows MRP-139 and therefore also addressed PWSCC in butt welds applicable to this IN.

- NRC Regulator Issue Summary 2018-06 (December 2018) “Clarification of the Requirements for Reactor Pressure Vessel Upper Head Bare Metal Visual Examinations” clarified the requirements for bare-metal visual examination to meet the requirements of Notes 1 and 4 in Table 1 of American Society of Mechanical Engineers (ASME) Code Case N-729-4. As identified in the RIS, some recent events illustrate how the requirements of Code Case N-729-4 can be misinterpreted by licensees. The clarification from this RIS for the requirements for the RPV upper head has been incorporated in fleet NDE procedures.

- In 2019, Materials Reliability Program (MRP) 384 Revision 1 was issued with guidance for planning and executing reactor vessel upper head (RVUH) penetration examinations in a manner that will minimize the likelihood of human errors and maximize the probability of success. This report provides guidance for utility personnel to effectively implement NEI 03-08 “Needed” and “Good Practice” requirements related to RVUH penetration tube examinations. The five recommended “Needed” and “Good Practice” NEI 03-08 requirements from MRP-384 will be integrated into the next ISI inspection intervals for PSL Unit 1 and 2.

The examples above demonstrate that the PSL 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. PSL will continue to monitor NRC Information Notices and Regulatory Issue Summaries. This ensures that the 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

PSL has been an active participant in the CE Owners Group (CEOG), later integrated into the Pressurized Water Reactor Owners Group (PWROG), EPRI and the Nuclear Energy Institute (NEI) initiatives regarding cracking of Alloy 600 RCS components. The Alloy 600 Inspection Program was created in response to NRC Generic Letter 97-01 and updated in response to Bulletin 2001-01.

PSL performed the original visual inspections on the top of the Units 1 and 2 reactor vessel heads for leakage as part of the Boric Acid Corrosion Program (Section B.2.3.4). No evidence of leakage from the Alloy 600 reactor vessel head penetrations was identified. Volumetric examinations were performed at several more susceptible CE plants as identified in NEI Letter, “Response to NRC Request for Additional Information on Generic Letter 97-01, Project Number 689,” and were effective at detecting primary water stress corrosion cracking.

The 100% bare metal baseline visual inspection performed at PSL Unit 2 in response to Bulletin 2001-01 was completed. The inspections performed at PSL Unit 1 in response to Bulletins 2001-01 and 2002-02 were also completed. The results showed that the reactor vessel head was free of any leakage coming from the reactor vessel head penetrations.

In 2005 and 2007, for PSL Units 1 and 2 respectively, RPV closure heads with Alloy 600 CEDMs were replaced by new heads with CEDMs made with more resistant Alloy 690 material. Future inspections of the new reactor vessel heads are in accordance with ASME Code Case N-729 which has been included in the site augmented in-service inspection program including the conditions listed in 10 CFR 50.55a. The visual inspections of the insulated reactor vessel head to penetration area are performed in accordance with the Boric Acid Corrosion Program (Section B.2.3.4).

In 2005, the PSL Unit 1 pressurizer was replaced with a new, like-for-like pressurizer, with Alloy 690 material replacing all components previously composed of Alloy 600. Visual inspections performed at PSL Units 1 and 2 have identified leakage of Alloy 600 pressurizer and Class 1 piping instrument nozzles. In all cases, the leaking nozzles have been removed and replaced in accordance with the requirements of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1). The visual inspections provided timely detection and repair of the RCS pressure boundary leakage.

In 2018, a boric acid leak was identified at PSL Unit 2 during an ISI bare metal visual inspection of the pressurizer level nozzle at the piping to pressurizer interface. Contingency related activities were created including preparation of replacement material, engagement of the repair vendor, and the determination for the need for a pre-planned work order. Subsequent engineering review determined through wall penetration occurred within Alloy 600 weld pad parent metal, not at the J-weld interface to the pad. PSL replaced the existing Alloy 600 pad material with Alloy 690 pad material to provide improved resistance to primary water stress corrosion cracking (PWSCC) mechanisms. The response to this leak documents the program's ability to identify degradation and implement the corrective action program elements. No other condition reports have been written during the PEO for this program.

<u>Program Assessments and Evaluations</u>

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid Induced Corrosion in Reactor Coolant Pressure Boundary Components AMP were identified.

The PSL 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 PSL 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 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.2.3.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

Program Description

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP is an existing 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 PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1) is supplemented by the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP which monitors loss of fracture toughness due to thermal embrittlement for ASME Code Class 1 CASS components with service conditions above 482°F.

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 PSL 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 RCS piping, RCS system valve bodies, RCS pump casings, and reactor vessel internal components.

PSL has chosen the evaluation method to disposition reduction in fracture toughness due to thermal aging embrittlement of RCS piping and RCP casings. The component-specific flaw tolerance evaluations in SLRA Section 4.7.7 determined that the results for susceptible CASS piping and pump casings 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 PSL 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 PSL Reactor Vessel Internals AMP (Section B.2.3.7).

NUREG-2191 Consistency

The PSL Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel” as modified by SLR-ISG-2021-02-Mechanical, “Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance”.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

PSL evaluates industry OE items for applicability per the NextEra Fleet OE Program and takes corrective actions, when necessary. The PSL Thermal Aging Embrittlement of Cast Austenitic Stainless Steel 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” RCP 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” RCP 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.

Point Beach Nuclear Plant:

- In 2020, during a liquid penetrant exam of the Unit 1A RCP integrally welded attachment weld, two recordable indications were observed. These were linear indications located on the RCP casing. The flaws exceeded acceptance criteria requiring an additional examination during the current outage. However, the flaws were evaluated and determined to be casting flaws, not thermal aging embrittlement.

Plant Specific Operating Experience

As part of the original license renewal application, baseline ultrasonic examinations were performed of potentially susceptible components to verify the absence of the initial postulated flaw size. The PSL-1 baseline flaw examinations in 2015 (SL1-26) revealed no existing crack like indications with a 25% through wall depth. The PSL-2 baseline flaw examinations in 2017 (SL2-23) also revealed no existing crack like indications with a 25% through wall depth. Therefore, no crack depth adjustments are to be made to the calculated final crack size.

A review of 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).

Program Assessments and Evaluations

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP were identified.

The PSL 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 PSL Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP provides 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.2.3.7 Reactor Vessel Internals

Program Description

The PSL Reactor Vessel Internals AMP is an existing AMP with the following principal objective[s]:

- Manage the effects of age-related degradation mechanisms that are applicable to pressurized water reactor (PWR) reactor vessel internal 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

The PSL reactor vessel internals program implements 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. The PSL reactor vessel internals program for the original 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 1.6.26). The staff approved the initial PSL license renewal reactor vessel internals program report (NUREG-1779) which was developed in accordance with MRP-227-A. PSL has continued to update the program as industry guidance is released and is currently implementing the most recent guidance (MRP-227 Revision 1-A).

The PSL 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 OE 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. Note that MRP-227 Revision 1-A still only addresses an operating period of 60 years and was implemented at PSL for the current period of extended operation in June of 2020. 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 PSL 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 internal components at PSL. These examinations provide reasonable assurance that the effects of age-related degradation mechanisms will be managed during the SPEO. This AMP includes expanding periodic examinations and other inspections if the extent of the degradation identified exceeds the expected levels.

MRP-227 Revision 1-A provides guidance for selecting reactor vessel internal 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 reactor vessel internals 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 reactor vessel internals component locations are specified to expand the inspection sample should the Primary Component indications be more severe than anticipated.

A third set of reactor vessel internals 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 reactor vessel internals 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, two reactor vessel internals component locations are added to the Primary Components inspection category in addition to those identified in MRP-227 Revision 1-A. In addition, one component is added to the Expansion Components inspection category.

The two reactor vessel internals component locations added to the Primary Components inspection category are the core shroud tie rods and core stabilizing lugs, shims, and bolts. The reactor vessel internals component added to the Expansion Components is the fuel alignment plate. These additions are consistent with the MRP 2018-022 guidance. -

The PSL Reactor Vessel Internals AMP relies on the PSL 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 PSL 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 the most recent revision of MRP-228. The PSL Reactor Vessel Internals AMP will be enhanced to align the examination method, frequency, and examination coverage to those in MRP-2018-022. 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 reactor vessel internal 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 reactor vessel internal components (e.g., redundant bolts or pins used to secure a fastened reactor vessel internals 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 PSL 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.

The PSL 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 reactor vessel internals component and is extensive enough to warrant a supplemental flaw growth or flaw tolerance evaluation.

For singly-represented components, the PSL 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 provide reasonable assurance that the cause of the condition is determined and that corrective action is taken 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 in the subsequent period of extended operation.

NUREG-2191 Consistency

The PSL Reactor Vessel Internals AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M16A, “Reactor Vessel Internals”, as modified by SLR-ISG-2021-01-PWRVI, “Updated Aging Management Criteria for Reactor Vessel Internal Components for Pressurized-Water Reactors”.

Exceptions to NUREG-2191

None.

Enhancements

The PSL Reactor Vessel Internals AMP will be enhanced as follows, for alignment with NUREG-2191, as modified by the interim staff guidance. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	For new components added through the analysis in Appendix C, the appropriate inspection interval will be enhanced to identify these component inspections as subsequent license renewal commitments. Alternatively, PSL will implement the latest NRC-approved version of MRP-227 if it addresses 80 years of operation.
5. Monitoring and Trending	The examination and re-examination schedules in the reactor vessel internals program procedure will be enhanced to be implemented in accordance with MRP-227 Revision 1-A (as supplemented by Appendix C). Alternatively, PSL will implement the latest NRC-approved version of MRP-227 if it addresses 80 years of operation.
6. Acceptance Criteria	The reactor vessel internals program procedure will be enhanced to incorporate the updated examination acceptance criteria in MRP-227 Revision 1-A (as supplemented by a gap analysis). Alternatively, PSL will implement the latest NRC-approved version of MRP-227 if it addresses 80 years of operation.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

Tracking of active degradation mechanisms informs the program on potential issues which are evaluated for potential augmented inspections or material modifications. Several issues throughout the industry have been identified, evaluated, and dispositioned for relevance to PSL:

- Technical Bulletin (TB) TB-14-5

  Westinghouse released TB-14-5, "Reactor Internals Lower Radial Support Clevis Insert Cap Screw Degradation" providing an update on the issue of degradation of Westinghouse clevis insert bolts and potential degradation of Combustion Engineering core stabilizing lug bolts. Prior to TB-14-5, there had been a previous InfoGram from Westinghouse (IG-10-1). IG-10-1 documented failed clevis insert bolts at DC Cook which was the first PWR to observe this issue. TB-14-5 supersedes InfoGram IG-10-1 with regards to the impact to PSL. While a specific evaluation was not performed for the Combustion Engineering units, a qualitative comparison of the design features, installation, and loading reached the conclusion that the snubber lug will be able to perform its intended safety function in the event of bolt failures. The TB also indicated that during 10-year ISI inspections when the internals are removed there is potential for a failed insert to dislodge and present difficulties during re-installation of the internals. The OE was included into the reactor vessel internals aging management program for PSL Units 1 and 2 for their core stabilizing lug bolts. Prior inspections of Unit 1 performed in 2008 showed no recordable indications at the core stabilizing lugs and core barrel snubber block. Prior inspections of Unit 2 performed in 2012 did show recordable indications on the interfacing components, core barrel snubber blocks at 0 and 180 degrees, as well as deformed areas on the upper left corner of each snubber block. No immediate actions were necessary.

MRP-2017-024 was subsequently issued to address TB-14-5 and distribute the OE to the program participants. PSL had already addressed the contents of TB-14-5 and had no further actions. This was reviewed by the program.

- MRP 2019-001

  EPRI released MRP 2019-001, "Materials Reliability Program: Inspection Standard for PWR Internals – 2017 Update (MRP-228 Revision 3)" which issued MRP-228 Revision 3. The revised guidelines in MRP-228 contains five "Needed" and three "Good Practice" requirements as specified in Section 4 of MRP-228. PSL reviewed this guidance and determined the requirements will be implemented for future inspections. The Unit 1 baseline inspections were completed prior to the issuance of this guidance, and the Unit 2 inspections are scheduled for 2023-2025. PSL will implement the inspection requirements for the next relevant inspection for each Unit as applicable. Subsequent to this interim guidance, a newer revision of MRP-228 was issued in 2021, and it will be implemented prior to the next relevant inspection for each Unit.

- MRP 2019-002

  EPRI released MRP 2019-002, "Interim Guidance to MRP-227-A NEI 03-08 Needed Requirements for US Domestic PWR Plants Implementing 'Flexible Power Operations'" which provides interim guidance for Westinghouse-designed plants. PSL reviewed this interim guidance. PSL is a Combustion Engineering designed plant which is substantially less susceptible to flexible operation complications as compared to Westinghouse plants. As such, PSL would not be impacted by flexible operation as long as the Units operate within their design transient cycles. In addition, both PSL Units have operated under base load conditions over the life of the Units and do not have any current plans to implement flexible power operation.

- MRP 2019-009

  EPRI released MRP-2019-009, "Transmittal of NEI-03-08 'Good Practice' Interim Guidance Regarding MRP-227-A and MRP-227, Revision 1 PWR

Core Barrel and Core Support Barrel Inspection Requirements" which addresses core support barrels in CE plants and core barrels in Westinghouse plants. The interim guidance is a NEI 03-08 "Good Practice" recommendation to inspect the core barrel axial welds: middle axial weld (MAW) and lower axial weld (LAW). The guidance identifies plants that may have limited accessibility to these welds, and inspection guidance is provided.

MRP 2019-009 is a follow-up industry action from the initial letter issued in 2018 that communicated the findings during the spring 2018 refueling outage on Unit 1 (Reference MRP 2018-028). During the spring 2018 outage, flaws were identified on the Unit 1 CSB and core shroud assembly (CSA). The majority of the flaws were identified on the CSB middle axial weld (MAW). After the spring 2018 outage, PSL completed an apparent cause evaluation. The apparent cause review led to similar conclusions regarding the potential causes to those discussed by the OEM in Attachment 1 and 2 of MRP 2019-009. The Unit 1 CSB flaws were believed to be tied to stresses from fabrication or from the early-life CSB repairs performed due to thermal shield failure in the mid-1980s. PSL completed an advanced flaw evaluation to justify a 10-year inspection interval (relative to the 2018 inspection) for the existing flaws. Additional work was completed to include re-inspection of the existing flaws during the fall 2019 outage to validate the crack growth rate assumption. The 2019 inspections resulted in a confirmation of a 10-year inspection interval.

- MRP 2020-011

  EPRI released MRP-2020-011, "Notification of Recent OE Related to Displaced PWR Clevis Insert Assembly" which communicates OE at Ginna from the spring refuel outage of the reactor vessel internals lower radial support clevis insert assembly where they observed partial displacement at one lower radial support clevis insert. These components are referred to as core stabilizing lug hardware within the CE design. At the point of issue for this OE PSL had completed the baseline inspections for Unit 1 and had baseline inspections planned for Unit 2 during spring 2023. The evaluation for the existing flaws on the Unit 1 core barrel justified a 10-year inspection interval from the 2018 inspection. As such, there were no immediate impacts to the program. Contingency actions were established for the NEE fleet to review for inclusion in upcoming outages with planned core barrel removal. This was evaluated by PSL and added to the implementing program document.

- MRP 2020-007

  EPRI released MRP-2020-007, "NRC Acceptance of MRP-227 Revision 1-A Topical Report Titled 'Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluations Guideline' for PWR Licensing Referencing" which communicates the NRC's acceptance letter of the latest revision of MRP-227, Revision 1-A, as well as OE and new knowledge gained from various materials testing, modeling, and research projects. This latest revision of MRP-227 was implemented at PSL in June of 2020 and will define the scope and acceptance criteria of future inspections.

Plant Specific Operating Experience

- During the 1983 PSL Unit 1 refueling outage, the RVI core support barrel (CSB) and thermal shield assembly were observed to be damaged. See further discussion in SLRA Section 4.7.3.

- PSL completed baseline inspections of the reactor vessel internals on Unit 1 in 2018. Flaws were identified on the core support barrel and the core shroud assembly. Flaws were primarily at or near the core support barrel middle cylinder axial weld (MAW). Evaluations were performed during the outage to disposition the indications for one cycle of operation using the guidance of WCAP-17096-NP-A, certain generic inputs from WCAP-17684, and plant specific inputs.

  During the fall 2019 outage, PSL performed a follow-up inspection of the Unit 1 core support barrel and core shroud assembly to confirm the assumptions of the evaluation and inspect for any unexpected flaw growth. The inspection found no overall evidence of flaw growth. Due to the large number of flaws on the core support barrel MAW, a permanent repair strategy is being pursued to support the next planned inspection tentatively during the spring 2027 outage. The follow-up inspection was also evaluated using the guidance of WCAP-17096-NP-A. Both the site-specific evaluations were submitted to the NRC to show the justification with margin for continued operation (Reference ML20134J047).

- During the 2018 Unit 1 ASME XI ISI core barrel visual examination, wear was identified on the reactor vessel stabilizer blocks/lugs (RVSB-1, RVSB-3, RVSB-5, and RVSB-6). In addition, the locking pin on the lower left side was protruding and the locking pin on core stabilizer lug 6 left side upper and lower was protruding. Westinghouse performed an evaluation of these indications which concluded continued operation for the core stabilizer blocks would be safe through the subsequent 10-year interval without repair, replacement, or re-evaluation needed. The wear observed in all the locations was determined to be primarily minor, surface wear.

Program Assessments and Evaluations

- PSL informed the NRC through a June 14, 2011 letter (Letter No. L-2011-556) that they would be modifying the prior reactor vessel internals AMP and implementing the guidance of MRP-227-A. PSL submitted this inspection plan on September 28, 2015 (Reference ML15300A574) outlining the appropriate inspections and acceptance criteria for the initial period of extended operation. At the time of the Unit 2 inspection, the NRC was still reviewing the Unit 2 application addressing MRP-227-A and as such, the PSL Unit 2 reactor vessel internals AMP was not included in the post approval Phase 2 inspection. The NRC subsequently approved the Reactor Vessel Internals AMP and inspection plan on May 2, 2018 (Reference ML18071A002). Currently, PSL has maintained the reactor vessel internals program to the most recently approved NRC guidance as discussed above in the site's response to MRP 2020-007.

- The NRC conducted a post approval site inspection review in 2015 which evaluated two commitments made relative to the Reactor Vessel Internals AMP during initial license renewal. The first commitment stated prior to the PEO of Unit 1, PSL would submit a report summarizing the aging effects applicable to reactor vessel internals, including a description of the inspection plan. The second commitment relative to reactor vessel internals stated that prior to the PEO of Unit 1, PSL would perform a one-time inspection of the reactor vessel internals.

  On June 14, 2011, PSL submitted letter L-2011-255 to the NRC (ADAMS Accession Number ML111650362) documenting PSL's commitment to substitute the previous NRC-approved plant-specific Reactor Vessel Internals AMP for the NRC-approved MRP-227-A program, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines." By adopting MRP-227-A, the reactor vessel internals inspections would be performed on a periodic basis rather than a one-time inspection. On September 28, 2015, PSL submitted letter L-2015-229 to the NRC (ADAMS Accession Number ML15300A574) describing the summary of aging effects on the reactor vessel internal components. The letter also described that the implementation of MRP-227-A required completion of the first inspection within two cycles of operation after the date of the PEO. Therefore, the first of these inspections on Unit 1 was scheduled for the spring refueling outage in 2018. Additionally, Letter L-2014-192 from the licensee to the NRC (ADAMS Accession Number ML14205A442) clarified the updated commitment and the inspection plan submittal dates. At the time of this inspection, the NRC was in the process of reviewing the licensee's submittals and no final SER was issued. The NRC subsequently approved the Reactor Vessel Internals AMP and inspection plan on May 2, 2018 (Reference ML18071A002).

  The inspectors reviewed a sample of the license renewal program basis documents and plant administrative procedures, in order to obtain reasonable assurance that the Unit 1 program was developed based on the recommendations described in the MRP-227-A for a Combustion Engineering type reactor. The inspectors interviewed PSL personnel to discuss the status of the planned inspections for the Unit 1 reactor during the spring refueling outage in 2018. The inspectors reviewed a sample of inspection items and inspection techniques required by MRP-227-A, to verify that the planned inspection included the required type of inspections, and included provisions for corrective actions using the existing corrective action program (CAP), as well as consideration of site-specific and external OE. The inspectors were informed that the first inspection of the Unit 1 reactor vessel internals will be tracked in the corrective action program (CAP) which ultimately developed the inspection program.

  The inspectors also reviewed the program to verify that it addressed an MRP-227-A provision that requires licensees to address any plant-specific issues not addressed by the MRP-227-A guidelines. Specifically, the Unit 1 core barrel was repaired in 1983 to address areas with through-wall cracks. The affected locations were repaired by drilling crack arrester holes, and the holes were sealed by inserting expandable plugs. As part of the review, a

TLAA for the core support barrel middle cylinder addressed the fatigue of the core support barrel mid-cylinder and the expandable plug preload analysis, to demonstrate that these reactor internal components will continue to perform their intended function given the predicted fluence, operating temperature, operating hydraulic loads, and thermal deflections for the PEO. This TLAA is presented for the SPEO in Reference 9.15.

The inspectors reviewed a sample of the fatigue analysis conclusions and confirmed the components would continue to accomplish their respective functions.

- In 2018, PSL assessed the PSL Units 1 and 2 Reactor Vessel Internals Program. This assessment captured the elements of NEI 03-08 “Guidelines for the Management of Material Issues” Revision 2. The goal of the assessment was to ensure that all materials related requirements and good practices were being addressed in a proactive manner and were fully compliant within the PSL Reactor Vessel Internals AMP.

  No new findings were identified. Five existing findings tracked under a separate assessment were summarized in this report. In addition, four program enhancements were identified. Overall, the PSL reactor vessel internals program was evaluated to have been performed in accordance with existing NEI 03-08 requirements, specifically in accordance with MRP-227-A and associated interim guidance.

- In 2018, PSL reviewed the implementation of the reactor vessel internals program. As part of this review PSL reviewed ARs associated with the program across the fleet to recognize inconsistencies and opportunities for improvement within aging management throughout the NEE fleet. PSL had no findings related to meeting the identified performance criteria.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and some findings related to the PSL Reactor Vessel Internals AMP were identified. The initial finding identified that the reactor vessel internals inspections were tracked through an AR assignment rather than a preventive maintenance (PM) activity. This was resolved by generating a PM activity to track future reactor vessel internals inspections.

The PSL 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 PSL Reactor Vessel Internals 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.2.3.8 Flow-Accelerated Corrosion

Program Description

The PSL 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 1.6.27) for an effective Flow-Accelerated Corrosion AMP.

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 PSL Flow-Accelerated Corrosion 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), which result 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. 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 PSL Flow-Accelerated Corrosion 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 PSL Flow-Accelerated Corrosion AMP also manages wall thinning caused by erosion mechanisms in limited situations where periodic monitoring is used in lieu of eliminating the cause, typically a design or operational condition, 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 PSL Flow-Accelerated Corrosion AMP is a condition monitoring AMP. 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. Preventative action is taken in response to conditions identified from the results of the Flow-Accelerated Corrosion AMP inspections. These actions are driven by the corrective action program.

NUREG-2191 Consistency

The PSL Flow-Accelerated Corrosion AMP, with enhancement, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M17, "Flow-Accelerated Corrosion."

Exceptions to NUREG-2191

None.

Enhancements

The PSL 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% of plant operating time (as allowed by NSAC-202L-R4) to ensure the exclusion remains valid and applicable for operation beyond 60 years. If actual wall thickness information is not available for use in this re-assessment, a representative sampling approach will be used. This re-assessment may result in additional inspections. The existing System Susceptibility Evaluation (SSE) identifies components that are excluded due to infrequent operation and components that are excluded due to a combination of infrequent operations above a temperature threshold. These excluded components require a re-assessment to ensure that

Element Affected	Enhancement
	the exclusion remains valid and applicable for operation beyond 60 years. • Extend the erosion inspection plan for the duration of the SPEO.
3. Parameters Monitored or Inspected	• Extend the erosion inspection plan for the duration of the SPEO.
4. Detection of Aging Effects	• Extend the erosion inspection plan for the duration of the SPEO. • Perform opportunistic visual inspections of internal surfaces during routine maintenance activities to identify degradation.
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 PSL Flow-Accelerated Corrosion AMP consider pertinent industry OE, 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 PSL.

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 Erosion Susceptibility Evaluation (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 OE indicates the Flow-Accelerated Corrosion AMP is robust and that numerous work orders, CRs/ARs have been issued as a result of or to evaluate evidence of flow-accelerating corrosion.

The PSL Flow-Accelerated Corrosion AMP is a mature, established program.

A review of the quarterly program health reports for 2015 through 2020 determined that the PSL Flow-Accelerated Corrosion AMP has been green for all of 2020. Prior program health reports identified isolated incidents of components that exceeded the timelines of repair/replacements and development of plan to reconcile the program to NSAC-202L-R4. Issues were corrected via the corrective action process, and no repeat failures were found. The PSL Flow-Accelerated Corrosion AMP tracks and trends quarterly program health reports and takes timely action to mitigate issues arising from the health reports.

In January 2011, a section of piping was identified that would not meet minimum wall thickness requirements using the projected design corrosion allowance at EPU conditions. The piping was projected to fall below minimum wall thickness after one cycle of operation at EPU conditions. The section of piping was re-designed using FAC resistant material.

In January 2011, a 20-inch diameter pipe in the line from a low pressure feedwater heater on Unit 2 was determined to have wall thinning less than the screening criteria per the Flow-Accelerated Corrosion (FAC) Ultrasonic Thickness Report. While the wall thinning did not fall below the value for minimum wall thickness, operation through the next cycle would result in a reduction of wall thickness to below this value. Weld repairs were performed under a workorder extending the life of the pipe for a minimum of three cycles followed by a re-inspection. The piping was re-inspected, and no further degradation that would require a corrective action has been reported.

In April 2011, evidence of significant wear due to FAC was identified on an elbow. The wall thickness indicated by computed radiology was less than the required minimum wall thickness. The elbow was replaced.

In August 2012, wall thickness readings on an elbow identified that one small area would likely fall below required wall thickness within one cycle of EPU operation. The secondary circumferential weld toe-scan measurement results at the downstream weld indicated that a small area has a measured thickness below the screening criterion, but above the minimum thickness. Weld repairs were performed to extend the life of the elbow an additional five cycles. The region was re-inspected and re-assessed during a subsequent outage and the fitting was determined to be acceptable for an additional 5 more cycles.

In October 2013, Unit 1 condensate system piping had wall thickness readings below the screening criteria. The observed reduced wall thickness was caused by weld prep of the piping butt weld and that the wear rate indicated by the FAC inspection overstated the actual value of wear. Re-inspection of the component was performed after one cycle to develop a point-to-point wear rate and no further issues were found.

In March 2014, 12-in diameter pipe in the Unit 2 extraction steam system had as-found wall thickness measurements below the screening criterion. The location would approach the minimum wall thickness criterion in the next cycle if the conservative erosion rate was used. The location was judged acceptable for 2 cycles based on the reduced erosion rate observed at surrounding locations. The reduced erosion rate was attributed to changes in secondary chemistry over the years. The location was scheduled to be re-inspected and reassessed during the next outage at which time the piping was replaced with chrome-moly material.

In April 2015, a location below minimum wall thickness in the feedwater pump suction piping was identified by FAC examination, and a work order performed a weld repair of the piping.

In September 2015, the primary measurements from the FAC Ultrasonic Thickness Report on piping in the Unit 2 condensate system confirmed that each gridded wall thickness measured was above the screening criterion. However, an isolated measurement from the downstream circumferential weld scans indicated one value below the screening criterion. While the wall thicknesses measurements were above minimum wall, operation though the next cycle would have likely resulted in a reduction of a small area of pipe wall below the minimum allowable value. Weld build-ups were performed, and the location is scheduled to be re-inspected at a future outage to reassess the extent of accelerated wall thinning.

In April 2018, close examinations of the 1A and 2A feedwater heater cladding support tabs, tubesheet support bracing welds inside the 1A condenser, and 1A condenser spray nozzle heads revealed that some of the welds showed signs of erosion and were cracked or damaged due to corrosion. Weld repairs were performed in the following refueling outage.

In October 2019, piping in the Unit 1 condensate system had wall thickness readings approaching minimum wall and the screening criteria. The minimum wall thickness criterion was met at each of the measured grid locations. However, the wear rate predicted that eight nodes would be below the minimum wall thickness by the next outage. Weld build-ups were performed at contiguous grid locations, and they are scheduled to be re-inspected at the next outage to re-quantify the extent of accelerated wall thinning.

Program Assessments and Evaluations

In November 2010, a self-assessment was performed to identify areas that were not completed for PSL LR commitments, and findings were identified. One commitment expanded the scope of the PSL Flow-Accelerated Corrosion AMP to include internal and external loss of material of drain lines and selected steam traps. The PSL Flow-Accelerated Corrosion AMP manages the aging effect of loss of material due to

FAC by predicting, detecting, monitoring and mitigating FAC in high energy carbon steel piping associated with the main steam, reactor coolant (steam generators), main feedwater, and blowdown systems, and is based on industry guidelines and OE.

In November 2015, the NRC completed a post-approval site inspection for License Renewal for Unit 1 in accordance with NRC IP71003; the comparable inspection for Unit 2 was completed in November 2017. The inspectors reviewed the licensing basis, program basis document, implementing procedures, and completed inspections; and interviewed the PSL plant personnel responsible for the program. The inspectors verified that the program and associated enhancements and commitments were in place. Based on review of the timeliness and adequacy of the licensee actions, the inspectors determined PSL had met the required commitments for the PSL Flow-Accelerated Corrosion AMP.

AMP effectiveness is assessed at least every five years basis per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Flow-Accelerated Corrosion AMP were identified.

The PSL 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 PSL 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

The PSL Bolting Integrity AMP, previously part of the Systems and Structures Monitoring Program and Periodic Surveillance and Preventative Maintenance Program, is an existing AMP that will manage loss of preload, cracking, and loss of material for closure bolting for SR and NNS pressure-retaining and other mechanical components using preventive and inspection activities. This AMP also will manage 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 1.6.28) , “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants,” EPRI NP-5769 (Reference 1.6.29), “Degradation and Failure of Bolting in Nuclear Power Plants,” EPRI Report 1015336 (Reference 1.6.30) , “Nuclear Maintenance Application Center: Bolted Joint Fundamentals,” and EPRI Report 1015337 (Reference 1.6.31), “Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints.”

The preventive actions associated with this AMP will 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 kilo-pounds per square inch); lubricant selection (e.g., not allowing the use of molybdenum disulfide); proper torquing 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. These actions are taken to preclude loss of preload, loss of material, and cracking.

The PSL Bolting Integrity AMP will provide inspection of pressure-retaining bolting per ASME Code requirements. Pressure-retaining bolted connections will be inspected at least once per refueling cycle as part of ASME Code Section XI leakage tests. Inspections will be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspections will follow site procedures that include inspection parameters for items such as lighting and distance offset that provide an adequate examination.

This AMP will supplement 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 (at least once per refueling cycle) will provide reasonable assurance of timely identification of indications of loss of preload (leakage), cracking, and loss of material. Visual inspection methods will be effective in detecting the applicable aging effects, and the frequency of inspection will be adequate 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 corrective action program.

The environment of the bolts inspected by the PSL Bolting Integrity AMP are either air (indoor uncontrolled or outdoor), soil, or raw water. The source of raw water for the intake cooling water systems at both Units are the same. There is no OE or reason to believe that the air (indoor uncontrolled or outdoor), soil, or raw water environments of the bolting of one Unit would be any worse than that of the other Unit except where borated water leakage may occur. As such, a maximum of 19 bolt heads and threads per Unit will be used for the representative samples unless future OE indicates a difference in the environments. The inspections will include 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.

Submerged closure bolting that precludes detection of joint leakage will be inspected visually for loss of material during maintenance activities. Bolt heads will be inspected when made accessible and bolt threads will be inspected when joints are disassembled. In each 10-year period during SPEO, a representative sample of bolt heads and threads will be 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.

For bolted joints that contain air or gas, the acceptability of the closure bolting will be evaluated on a case-by-case basis using one of the following methods:

- Inspections will be performed consistent with that of submerged closure bolting;
- A visual inspection for discoloration will be conducted (applies when leakage of the environment inside the piping systems would discolor the external surfaces);
- Monitoring and trending of pressure decay will be performed when the bolted connection is located within an isolated boundary
- Soap bubble testing will be performed; or
- Thermography testing will be 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.

High-strength closure bolting [actual measured yield strength greater than or equal to 150 ksi (1,034 MPa)] may be subject to SCC. For all 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) and closure bolting for which yield strength is unknown, volumetric examination in accordance to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, is performed (e.g., acceptance standards, extend and frequency of examination). Specified bolting material properties (e.g., design and procurement specifications, fabrication and vendor drawings, material test reports) may be used to determine if the bolting exceeds the threshold to be classified as high-strength.

Indications of aging in ASME pressure retaining bolting will be evaluated in accordance with Section XI of the ASME Code. Non-ASME Code inspections will follow acceptance criteria established in plant procedures and specifications. Leaking joints do not meet acceptance criteria.

NUREG-2191 Consistency

The PSL Bolting Integrity AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M18, “Bolting Integrity”.

Exceptions to NUREG-2191

None.

Enhancements

The PSL 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	Update procedure(s) to reference EPRI Reports 1015336, 1015337, and NUREG-1339 and incorporate the guidance as appropriate for selection of bolting material and the use of lubricants and sealants.
2. Preventive Actions	Update procedure(s) to ensure that lubricants containing molybdenum disulfide (disulfide or polysulfide) or other lubricants containing sulfur will not be used on pressure-retaining bolted joints.
2. Preventive Actions 3. Parameters Monitored or Inspected	Update procedure(s) to ensure that the maximum yield strength of replacement or newly procured pressure-retaining bolting material will be limited to an actual yield strength less than 150 ksi.

Element Affected	Enhancement
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Create a new 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). The alternative testing will be completed on a case-by-case basis through – • Visual inspections of closure bolting during maintenance activities that make the bolt heads accessible and bolt threads visible, • Visual inspection for discoloration is conducted 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, or • Thermography testing when the temperature of the fluid is higher than ambient conditions.
4. Detection of Aging Effects	Update procedure(s) 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.
4. Detection of Aging Effects	Update procedure(s) to indicate that 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.
4. Detection of Aging Effects	Update procedure(s) to ensure that closure bolting inspections will include consideration of the guidance applicable for pressure boundary bolting in NUREG-1339 and in EPRI NP-5769.

Element Affected	Enhancement
5. Monitoring and Trending	Update procedure(s) and include in the new inspection procedure requirements 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.
7. Corrective Actions	Update procedures and include in the new inspection procedure the guidance for leakage monitoring and sample expansion and additional inspections if inspection results do not meet acceptance criteria as described in NUREG-2191, Chapter XI.M18, Element 7.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Fleet OE Program and takes corrective actions, when necessary. For example:

NRC Inspection and Enforcement Bulletin 82-02: This bulletin notified licensees about incidents of severe degradation of threaded fasteners (bolts and studs) in closures in the reactor coolant pressure boundary and required appropriate actions. In response to IE Bulletin 82-02, degradation of threaded fasteners in the reactor coolant pressure boundary as it pertains to PSL Unit 1 was reviewed. Two instances of significant leakage for Unit 1 reactor coolant pressure boundary bolted closures were noted. Both instances occurred due to boric acid corrosion and all affected studs were replaced. The response also noted that the two fastener lubricants utilized at PSL are Neolube on SS fasteners and Fel-Pro 5000 on carbon steel fasteners (Reference ML20062H876).

A follow-up response advised that a maintenance procedure was implemented, which included threaded fastener practices as required per IE Bulletin 82-02. In addition, during the 1984 outage of Unit 1, both steam generator manways (total of four) and the pressurizer manway were opened for maintenance and the subject fasteners were inspected and found to have no degradation. The fasteners were examined in the removed condition except for five, which had to be drilled out because of galling. All studs and nuts were replaced as part of a plant modification to improve the torquing methods used on these closures (Reference ML20095G735).

Plant Specific Operating Experience

The following summary of site-specific OE (which includes review of corrective actions and NRC inspections) provides examples of how PSL is managing aging effects associated with the PSL Bolting Integrity AMP.

- As part of an outage sampling inspection of the condenser expansion joint in October 2013, field workers recorded that some of the fasteners came loose by hand. Recorded breakaway torque ranged from 0 to 100 foot-pounds. The fasteners were originally torqued to 150 foot-pounds when installed.

  Based on OE from Turkey Point Unit 4, EPRI maintenance guidelines, and consultation with the expansion joint manufacturer, retorquing of all joint fasteners would guarantee seal integrity during the following operation cycle. In October 2013, an engineering evaluation, which included an extent of condition evaluation, was performed and the fasteners were retorqued to the required torque value.

- Three of the twelve bolts that secure the top motor shroud to a pump motor were identified as being in a degraded condition in June 2017. Each of the bolts that were in question were not adjacent to one another and so did not impact the pump's ability to perform its designed function. The bolts were cleaned, or replaced as needed, and retorqued in June 2017.

- During a walkdown in July of 2019 as a part of the current Systems and Structures Monitoring Program, a flange connection to a pump inlet was identified as having several bolts with surface corrosion at the threads. The structural integrity of the flange-to-pump connection was not compromised. Coating was removed from the piping, corrosion spots removed, a protective metal layer coating was applied, and then the piping was repainted.

- During a walkdown in July of 2019 as a part of the current Systems and Structures Monitoring Program, a flange connection to a pump discharge had several bolts with surface corrosion at the threads. The structural integrity of the flange-to-pump connection was not compromised and there was no impact to the operation of the pump. WOs were written to clean and apply coating to inhibit corrosion. This work is pending and planned to be completed as part of a future refueling outage.

- During a walkdown in July of 2019 as a part of the current Systems and Structures Monitoring Program, a flange connection to a pump suction had surface corrosion on the flange faces and on several bolts at the threads. The structural integrity of the flange-to-pump connection was not compromised and there was no impact to the operation of the pump. A work request (WR) was written to remove loose materials, clean surfaces, and prepare for coating. This work is pending and planned to be completed as part of a future refueling outage.

- During a walkdown in October of 2019 as a part of the current Systems and Structures Monitoring Program, corrosion build-up was noted on multiple nuts on a heat exchanger channel head. Replacement, repair, and touch-up coating application of the nuts was performed in October of 2019.

- During a walkdown in December of 2019 as a part of the current Systems and Structures Monitoring Program, a flange connection to a pump suction had surface corrosion on the flange faces and on several bolts at the threads. The structural integrity of the flange-to-pump connection was not compromised and there was no impact to the operation of the pump. WOs have been written to direct removal of loose materials and cleaning and preparing of surfaces for coating. This work is pending and planned to be completed as part of a future refueling outage.

- During a walkdown in February of 2020 as a part of the current Systems and Structures Monitoring Program, a 4-inch blind flange was identified as having corroded nuts and studs that need preventive coating applied. Structural integrity of the mechanical joint was not impacted. WOs were written and approved to perform the necessary work, which is scheduled to be completed in July 2022.

- During a license renewal walkdown, workers identified that the packing gland for a valve was heavily corroded. Some of the valve casing bolts were also corroded. There was no immediate concern with continued operation of the valve. Valve packing was determined to not be leaking. WOs were written and approved to perform the necessary work, which is scheduled to be completed by the end of 2021.

Program Assessments and Evaluations

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review of the current Systems and Structures Monitoring Program (which manages closure bolting for initial LR) was completed in January 2021. No findings were identified related to components in the scope of the PSL Bolting Integrity AMP.

The PSL Bolting Integrity 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 PSL 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 PSL Steam Generators AMP, previously the PSL 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 PSL ASME Section XI ISI, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1), and the PSL 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 PSL Technical Specifications (TS). Additionally, Administrative Control 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 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 PSL Steam Generators AMP is based on the guidelines provided in NEI 97-06 (Reference 1.6.32), Revision 3, "Steam Generator Program Guidelines." As such, this AMP incorporates the following industry guidelines:

- EPRI 3002007572, "PWR Steam Generator Examination Guidelines" (Reference 1.6.33);
- EPRI 1022832, "PWR Primary-to-Secondary Leak Guidelines" (Reference 1.6.34);
- 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 1.6.35); and
- EPRI 3002007856, "Steam Generator In-Situ Pressure Test Guidelines" (Reference 1.6.36).

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:

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 PSL 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).

The PSL Steam Generators 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 lancing 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 tube plug inspection, and replacement of tube plugs which are suspected of leakage. Additionally, this AMP works in conjunction with the PSL 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 72 effective full power months or every third refueling outage (RFO), whichever results in more frequent inspections. 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).

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 PSL 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 Steam Generator Integrity Assessment Guidelines. Assessment of tube integrity and plugging or repair criteria of flawed tubes is in accordance with the PSL 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 provide reasonable assurance 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.

Steam generator 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 Leak 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 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 PSL 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 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 in-service inspection.

NUREG-2191 Consistency

The PSL Steam Generators AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.M19, “Steam Generators.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

The PSL Steam Generators AMP has been effective in ensuring the timely detection and correction of the aging effects of tube degradation and/or loss of material in steam generator tubes. Comprehensive operational assessments are performed prior to each cycle of operation, and predictions made in operational assessments are benchmarked using inspection results. This benchmarking confirms the efficacy of the operational assessments. Any discrepancies noted during the benchmarking process are addressed in the operational assessment models.

The PSL Steam Generators AMP models the guidance provided in NEI 97-06, which has undergone extensive industry and NRC review. The current steam generator inspection activities have been evaluated against industry recommendations provided by EPRI and the steam generator suppliers. The overall effectiveness of the PSL Steam Generators AMP is supported by the successful identification of degradation in both Unit 1 and Unit 2, and by continually meeting the required tube integrity performance criteria.

The degradation modes known to have occurred in the world population of steam generators with Alloy 690TT tubes were reviewed for their applicability to the PSL Unit 1 and Unit 2 design. All forms of degradation, including both mechanical and corrosion related were considered.

The recent OE has been reviewed and documented. The review included recent NRC communications, EPRI Steam Generator Management Program (SGMP) Interim Guidance Letters and Information Letters, and INPO Industry OE.

- In October 2013, the NRC issued an Information Notice to address several instances where industry steam generators exhibited signs of degradation in the channel head. Cladding degradation was detected in the vicinity of the cold-leg drain line at an un-named foreign utility, and a rust-colored spot was identified near the primary face of the tubesheet along the weld connecting the divider plate to the channel head at Wolf Creek. At Surry Unit 2, a yellow stain was noted in the tube end of one of the tubes and on a portion of the channel head near this tube location Furthermore, a visual examination of the hot-leg primary manway flange face revealed degradation of the steam generator channel head and tubesheet. The issued were addressed by the existing procedures for the PSL Steam Generators AMP and no related issues were identified on PSL Unit 1 and 2 steam generators.

- The NRC published a license renewal interim staff guidance (ISG), Changes to Aging Management Guidance for Various Steam Generator Components. The ISG has been incorporated as operating experience information for the plants (like PSL Units 1 and 2) that already hold a renewed license per the ISG.

  The Unit 1 steam generators original equipment manufacturer (BWXT Canada) performed an evaluation which demonstrated that the tube-to-tubesheet welds met the minimum chromium content; therefore, the T/TS welds were determined to not be susceptible to crack initiation. The Unit 1 steam generators utilize a floating divider plate design so no crack initiation locations exist.

  For Unit 2, Alloy 690 components and weld materials are used in fabrication for both the tube-to-tubesheet welds and the divider plate assemblies. Therefore, a plant-specific AMP is not necessary.

- In October 2015, EPRI issued a Part 21 letter describing a change to the calibration of several eddy current technique specification sheets (ETSS). Based on a review of the data, there are no in-service steam generator tubes in PSL Unit 1 and Unit 2 that are affected by this issue.

- Industry-wide, there has been at least one tube rupture attributed to fatigue resulting from flow-induced vibration. The root cause of the failure was attributed to incorrect insertion of the anti-vibration bars (AVB) during steam generator fabrication. This particular phenomenon is limited to Westinghouse-designed steam generators where the AVBs are inserted from the top of the bundle after the tube bundle has been fully assembled.

- 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 tube support plate locations and wear from foreign objects.

There is no impact of past or recent operating experience reported by the industry on the present operation of the PSL Unit 1 and Unit 2 steam generators. Operating experience regarding corrosion type degradation is not considered relevant due to their advanced design and materials of the PSL steam generators.

<u>Plant Specific Operating Experience</u>

- A program health report review was performed covering the range of the first quarter of 2015 through the fourth quarter 2020. Health report attributes including owner proficiency, infrastructure, implementation, and equipment were Green for the majority of the review period. However, high tubing plugging rate in Unit 2 steam generator B due to mechanical wear at AVBs, and water hammer condition vulnerability on Unit 2 steam generators were gaps to Green. The plugging rate is being monitored during every outage. Visual inspection of the feedring and its supports in the Unit 2 steam generators is performed every outage due to a prior history of condensation-induced water hammer events.

- PSL Unit 1 Steam Generators
  - Steam generator tube in-service inspections during the fall 2016 refueling outage found no degradation during the visual inspection of the primary-side channel head bowls. No corrosion-related degradation was identified anywhere in the channel heads of the steam generators, and all previously installed tube plugs were confirmed to be in their correct locations and showed no visible signs of leakage based on the visual examination.
  - Each of the Unit 1 steam generators has 8,523 U-bend tubes fabricated from A690TT. There were a total of 155 tubes plugged in the Unit 1 steam generators following the inspection during the refueling outage in 2016. No tubes were plugged as a result of the pre-service examination. All plugging was due to wear at fan bar supports (including connector bars) except for one tube which was removed from service due to foreign object damage.
  - Recent industry experience of wear at tube support structures and incidents of tube-to-tube contact wear were evaluated for the Unit 1 steam generators. Tube wear at contacts with horizontal lattice grids was detected in tube examinations during previous refueling outages. Lattice grid wear is considered an existing degradation mechanism for Unit 1 steam generators; however the tube wear issues appear to have been resolved based on recent inspections.
  - In spring 2018, upper bundle flushes and sludge lancing were performed in both steam generators. Thirty-six and fifty-four pounds of sludge were removed from steam generators A and B, respectively. One foreign object was found in the annulus region of steam generator B cold leg near the 90-degree hand hole after sludge lancing. The object was removed during Foreign Object Search and Retrieval (FOSAR). The foreign object was a piece of wire and measured approximately 3-inches long and 1/32-inch in diameter. No scratches or degradation were found on the tubes in the region where the foreign object was found. No erosion, corrosion or damage mechanism was identified during Upper Steam Drum inspection in Steam Generator B.
- PSL Unit 2 Steam Generators
  - During restart from the spring 2014 refueling outage, foreign material was found in the B Steam Generator hot leg. The loose part inflicted damage to the hot leg channel head internals. One hot-leg plug was removed and replaced.

An engineering evaluation was performed to address the acceptability of the as-left damage caused by the loose part for one operating cycle.

Using a conservative Fatigue Strength Reduction Factor (FSRF), a fatigue evaluation was performed to assess the impact on the fatigue life of the 2B Steam Generator Primary Side Hot-Leg due to the loose part damage. The most limiting location was the Primary Manway, followed by the tube-to-tubesheet welds.

Additionally, a primary stress analysis of the tube-to-tubesheet was performed. The identified primary membrane stress under design conditions, the primary membrane stress under faulted conditions, and the primary membrane stress under test conditions were all less than the allowable limits defined in the ASME code.

A one-time inspection of all primary-side components including the tube-to-tubesheet welds was performed after the foreign object event. The follow-up visual inspection results confirmed that there was no breach in the cladding, and the integrity of the RCS pressure boundary was maintained.

- The past inspections revealed a large number of wear indications at AVBs. Although the number of detected wear indications is high relative to other Alloy 690TT plants, the Unit 2 experience with plugging is consistent with industry experience of the larger replacement steam generators which have been affected by early wear degradation.

- Each of the Unit 2 Steam Generators have 8,999 U bend tubes fabricated from Alloy 690TT. There was a total of 423 tubes plugged in the Unit 2 steam generators at the start of Cycle 23. All plugged tubes were preventive, except for thirty tubes in 2A steam generator where the measured Bobbin-sized depths associated with AVB wear exceeded the Technical Specification limit of 40% tube wear. No tubes required plugging as a result of the baseline inspection.

- In 2017, Eddy Current Testing of the Unit 2 steam generators and tube plugging were completed for the refueling outage. Thirty-eight tubes were plugged in steam generator A. Seventeen of these tubes were plugged as required by Technical Specifications; the remaining tubes were preventively plugged. No tubes in steam generator B were plugged or required plugging per Technical Specifications.

- In 2018, Steam generator tube plugging performed during the outage based on condition monitoring activities were documented. Seventy-nine tubes in steam generator A, and six tubes in steam generator B were plugged based on ECT inspection. Of the tubes plugged, twenty-seven in steam generator A (and none in steam generator B) met the requirements for plugging per Technical Specifications. The remaining tubes were preventively plugged.

- In 2018, during inspection of the feedring and supports in the Unit 2 steam generators, the c-bracket supports were found deformed. No other damage and/or deformation was found. The deformation of the c-brackets was limited, and the as-found gap between the feedring and the c-brackets was established to be 1.5-inches. The damage was likely caused by a pressure transient (water hammer) during a plant event which occurred in 2017. The deformation of the c-brackets was expected during this inspection based on previous similar experiences. The as-found condition of the c-brackets would not impede the ability of the feedring to perform its intended function, and as a result, there were no operability concerns. Contingency repairs to the feedring supports were performed under a work order.

Program Assessments and Evaluations

- In 2010, a self-assessment was performed to identify areas that were not completed for PSL License Renewal (LR) commitments. No findings regarding the PSL Steam Generators AMP were identified, and no license renewal commitments were changed since the SER was issued.

- In 2015, a focused self-assessment was performed to identify actions required to achieve readiness for the Unit 1 NRC License Renewal Implementation IP71003 Phase II Inspection. The review also included verification that licensing activities associated with the renewed operating licenses were being met and determined no gaps existed to support readiness of the subsequent IP71003 Phase I and II inspections.

- In 2017, self-assessment focusing on the readiness for the Unit 2 NRC License Renewal Implementation IP71003 Phase II inspections was performed. The assessment determined that License Renewal implementation was on track but identified items that needed to be addressed prior to the August 28, 2017 NRC Phase II inspection. These items were administrative and were tracked and resolved through the corrective action program.

Program Assessments and Evaluations

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and some findings related to the PSL Steam Generators AMP were identified. The review identified the need for new preventive maintenance (PM) activities and additional implementing procedures. The new PM activities and additional implementing procedures are included in the PSL Steam Generators AMP.

The PSL 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 PSL Steam Generators AMP provides 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.2.3.11 Open-Cycle Cooling Water System

Program Description

The PSL Open-Cycle Cooling Water System AMP is an existing AMP, previously part of the Intake Cooling Water System Inspection Program and the Periodic Surveillance and Preventive Maintenance (PSPM) Program, that manages the effects of aging on internal piping component surfaces exposed to a raw water environment from the intake cooling water (ICW) system. The PSL Open-Cycle Cooling Water System AMP applies to components constructed of various materials, including steel (e.g., carbon steel and gray cast iron), SS, nickel alloy (Monel), copper alloys (including copper alloys with greater than 8 % Aluminum or greater than 15% Zn), and fiberglass. The components managed by this include the ICW system piping/fittings and valves with a diameter greater than 20-inches, ICW strainers, component cooling water (CCW) heat exchangers (tube side), ICW orifices and thermowells, the connections between small bore and large bore piping, the turbine cooling water (TCW) heat exchangers' ICW system isolation valves, and the casings of the ICW pumps.

This objective is accomplished, in part, through implementing portions of the recommendations for the NRC Generic Letter (GL) 89-13 (Reference 1.6.37). NRC GL 89-13 defines the open-cycle cooling water system as a system or systems that transfer heat from SR systems, structures, and components (SSCs) to the ultimate heat sink (i.e., the PSL ICW system). This AMP manages aging effects through surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling, as well as routine inspection and maintenance, so that corrosion, erosion, protective coating failure, fouling, and biofouling cannot degrade the performance of systems serviced by the ICW system. One-time CCW heat exchanger performance testing was performed to demonstrate that tube cleaning frequency was sufficient to limit fouling (and resulting heat transfer capability) to what is assumed in the design calculations. When ICW system temperature or pressure differential readings exceed a specified level, then on-demand ICW system testing is performed to verify operability of the system. Inspection and examination methods include visual inspections, ultrasonic testing (UT) and eddy current testing (ECT) as appropriate. This AMP includes enhancements to the guidance in NRC GL 89-13 that address OE such that aging effects are adequately managed.

The PSL Open-Cycle Cooling Water System AMP monitors for 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 OE.

The CCW heat exchangers are periodically cleaned, visually inspected, and tested for tube wall thickness conditions (via ECT).

The ICW system at PSL does not currently have any concrete piping components exposed to raw water, 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, including the cementitious coatings, epoxy coatings, and epoxy repair patches on the interior of the ICW piping, is managed by the PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.3.28) AMP. Additionally, examinations of polymeric materials (i.e., rubber expansion joints) will be performed by the PSL External Surfaces Monitoring of Mechanical Components (Section B.2.3.23) AMP and/or the PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.3.24) AMP.

Inspection scope, methods, and frequencies are in accordance with the PSL GL 89-13 Program. The PSL GL 89-13 Program states that states that future tests or inspections are performed at intervals that provide assurance that equipment will be capable of performing its safety function.

The PSL 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. Although not required by Generic Letter 89-13, eddy current testing is performed for CCW heat exchanger tubes to verify tube integrity and quantify the extent of wall thinning or loss of material. Additional volumetric examinations, such as UT testing, may be utilized to measure the internal and external surface condition and quantify the extent of wall thinning or loss of material based on the evaluation of the examination results and as documented in accordance with the corrective action program. 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.

Satisfactory CCW heat exchanger performance is monitored by comparing ICW temperature and differential pressures across the CCW heat exchangers and ICW strainers with acceptable operating region curves in the ICW system operation procedures. In addition, CCW heat exchanger differential pressure is periodically monitored (operator shift rounds) to provide indication of flow blockage and heat removal capability.

Since the CCW heat exchangers are inspected for degradation in lieu of routine testing, inspection results are trended to evaluate adequacy of inspection frequencies. Corrosion cells are repaired as opposed to trending wall thickness. Wall thickness trending is only performed when a through-wall repair is performed while the plant is online and the application of the internal coating must wait until the next outage. In such a situation, trending is performed in accordance with the applicable ASME code case (e.g., N-513-4) until coating and additional repairs can be completed.

When a significant amount of fouling is identified within a CCW heat exchanger, an operability determination evaluation of the fouled heat exchanger is performed to confirm that the system maintains its required heat transfer capability.

The general acceptance criteria associated with the PSL 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 or macrofouling of marine growth and able to perform its intended functions as demonstrated by flow and performance testing. The PSL GL 89-13 Program contains details of applicable performance and flow testing.

Biofouling and particulate fouling in the CCW heat exchangers is undesirable. Automatic backflushing of the ICW Strainers removes accumulations of biofouling agents, corrosion products, and silt. Biological and particulate material not removed by backflushing is removed from the system when the system is opened for cleaning and inspection.

For this AMP, the relevant ICW system inspection specification fully addresses how internal surface coating damage and any underlying base metal damage is identified and tracked to resolution. Each area is either repaired or tracked for reinspection. The process does not rely on trending corrosion rates. Visual examinations of the internal surface of piping/fittings, heat exchangers, and ICW strainers are performed to identify loss of material. When required, determination of wall thickness values are performed and evaluated. Depending on the extent of degradation, a condition report may be initiated in accordance with the site corrective action process. 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.

Fouling and loss of material are corrected under plant procedures. When a condition report (CR) is generated, it is screened in accordance with the Corrective Action Program. Corrective actions to address the degraded conditions are developed and documented to provide reasonable assurance that the conditions adverse to quality are promptly corrected. If the condition is assessed to be significantly adverse to quality, the cause of the condition is determined, and an action plan is developed to preclude recurrence. When measured wall thickness is less than the design minimum wall thickness, the PSL Open-Cycle Cooling Water System AMP requires the condition to be identified/evaluated with an AR. Since PSL already performs periodic 100 percent inspections, of the ICW system piping, inspecting additional locations is not possible. Additionally, as the plant is required to be shutdown in order to perform the internal piping inspections, the current frequency is acceptable since degraded ICW system components are repaired prior to returning the system to service. Therefore, PSL does not have a need to increase the frequency of inspections or inspect additional locations for inspections that do not meet acceptance criteria.

NUREG-2191 Consistency

The PSL Open-Cycle Cooling Water System AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M20, “Open-Cycle Cooling Water System.”

Exceptions to NUREG-2191

None.

Enhancements

The PSL Open-Cycle Cooling Water System 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	Ensure program tests and inspections follow site procedures that include requirements for items such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes.
5. Monitoring and Trending	Ensure the primary program document and applicable procedures and preventive maintenance activities to include trending of wall thickness measurements at locations susceptible to ongoing degradation due to specific aging mechanisms (e.g., MIC). The PSL Open-Cycle Cooling Water System AMP will adjust the monitoring frequency based on the trending.
7. Corrective Actions	Ensure the primary program document and applicable procedures and preventive maintenance activities clarify that when components do not meet or are projected to not meet the next inspection's minimum wall thickness requirements, the program includes reevaluation, repair, or replacement of such components.
10. Operating Experience	Ensure that all above-ground, large-bore, SR ICW piping is replaced with AL6XN SS piping.
10. Operating Experience	Clarify within the applicable procedures, specifications, and preventive maintenance activities that the 100% internal inspections of the ICW header piping will be supplemented with localized volumetric examinations (UT, radiography, etc.) as applicable for areas where visual inspection alone is not adequate or as needed to determine the extent of degradation.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

The list below provides aging mechanisms and industry OE relevant to the PSL Open-Cycle Cooling Water 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 SS: LER 247/2013-004

In addition, industry OE identified a December 2019 industry event where the service water system at a plant was declared inoperable due to flow blockage caused by at least 15 feet of river sediment covering the service water pipe outfall. The OE was reviewed and no corrective action was required as the lessons learned previously had been captured in the PSL Open-Cycle Cooling Water System AMP.

Plant Specific Operating Experience

The respective ICW system health reports from January 2015 through October 2020 were reviewed. The ICW systems for Units 1 and 2 are currently graded “White”. Actions to return to “Green” are mainly coating repairs for external corrosion issues, pump replacements to restore margins, and ICW piping replacement at the intake and discharge to resolve external corrosion issues. There is currently a “White” work order to restore internal coatings with epoxy on a section of the Unit 1 ICW piping that has several epoxy repair patches.

A recent OE search was performed for SLR which covered a date range of October 1, 2010 through October 1, 2020. The ARs listed below are related to the in-scope ICW and CCW system and are focused on internal degradation, since external surfaces are not within the scope of the PSL Open-Cycle Cooling Water System AMP:

- In February 2020, one of the branch line connections to the ICW header showed loss of material at the branch-to-pipe weld after the corrosion products were cleaned by the internal pipe inspection team. Non-destructive examination (NDE) noted loss of material on the inner diameter mating surface up to ¾-inch width by ¾-inch depth. This was outside the maximum allowed degradation acceptance criteria of ¼-inch by ¼-inch. A work order cleaned, inspected, repaired, recoated, and reinstalled the sensing line flange prior to reinstalling the sensing line.

- In September 2016, a through-wall leak was identified on the Unit 2 “B” CCW heat exchanger discharge pipe. The leak rate was approximately 1 drop per minute. The exterior coatings were removed and the suspect area was inspected using a grid to determine pipe wall thickness using UT. The grid indicated that the nominal wall of the pipe was 0.344 inches to 0.375 inches. The UT grid showed an area of inner piping wall where the UT signal was not retrievable, indicating internal corrosion or erosion. A work order replaced the piping.

- In August 2016, during a GL 89-13 internal inspection of the Unit 1 “B” ICW header, a corrosion pit was identified within the internal piping area. The pit was on the interior of the vertical-to-horizontal elbow inside the 1A2 Intake Well. Pit-depth measurement by the certified pipe inspector showed the pit was 0.390 inches deep which was near through-wall. A work order performed the UT and a weld buildup repair on the piping.

- In October 2010, a UT examination of the Unit 2 “B” ICW discharge line downstream of an orifice identified degradation to the wall thickness of a pipe repair (patch plate) and also around the outside edge of the weld on the pipe. The UT readings indicated that wall thickness had decreased from the last inspection performed on 8/25/2010, and the as-found thickness had decreased from 0.312 inches to 0.212 inches. The degradation mechanism appeared to be internally driven erosion. Work orders performed a weld buildup repair and recoated the area. To reduce wall thinning due to jet impingement erosion, modifications were implemented in 2014 that replaced the orifice with a new design.

- In October 2010, a UT examination of the Unit 2 “A” ICW discharge line downstream of an orifice identified degradation to the wall thickness of a pipe repair (patch plate) and also around the outside edge of the weld on the pipe. The UT readings indicated that wall thickness had decreased from the last inspection performed on 8/9/2010, and the as-found thickness had decreased from 0.340 inches to 0.188 inches. The degradation mechanism appeared to be internally driven erosion. Work orders performed a weld buildup repair and recoated the area. To reduce wall thinning due to jet impingement erosion, modifications were implemented in 2014 that replaced the orifice with a new design.

- In April 2020, an approximately 5 gpm leak was identified on the Unit 1 ICW piping downstream of a flow element where a 1-inch pipe connects. The leak appeared to be at the half coupling weld toe to the 30-inch pipe. A work order installed a new half coupling to repair the leak.

- In April 2020, a through-wall leak was identified on the Unit 1 “B” ICW header just downstream of the ICW pump discharge isolation valve. A work request and work order repaired the leak.

- In January 2013, the ICW discharge lines on both Units downstream of the SR flow orifices were experiencing recurring pipe leaks caused by turbulent flow-induced erosion of the concrete liner or epoxy patches within the carbon steel piping. Work orders repaired the internal coating as needed. Modifications replaced the flow orifices with a new design which eliminated the turbulent flow erosion mechanism.

- In December 2011, three corrosion pit areas were reported on the downstream face of a Unit 1 ICW carbon steel flange. All three areas failed to meet minimum wall criteria. As such, a weld repair was needed to restore flange to code requirements. The three degraded areas had the following measurements: #1) corrosion pit 1-inch by 1-inch along the interior edge of the flange at the 8 o'clock position, #2 and #3) corrosion pits ½-inch by ½-inch along the interior face of the flange at the 6 and 7 o'clock positions. A work request and work order performed the weld buildup repair of the flange.

- In December 2011, while preparing to replace a degraded blank flange and associated 6-inch piping, a through-wall line breach was identified on the Unit 1 36-inch ICW piping at the 6 o'clock position. A work request and work order performed the weld buildup repair.

- In January 2011, engineering performed an internal visual inspection of a Unit 2 ICW discharge pipe. Previously, on 5/27/10, a 9-inch by 7-inch window plate was installed on this pipe without restoring the internal coating/lining. Restoration of the coating/lining was deferred to the refueling outage due to lack of internal coating access while making the on-line repair. When the internal surface of the pipe was inspected on 1/10/11, the area where the weld-buildup and patch plate replacement were located was found degraded to the point that the weld buildup was not considered suitable. The overall condition of the circumferential piping was good except for the area where weld build-up and window repair were performed. A work order performed a weld buildup repair and restored the coating.

- In December 2011, a diver inspection (internal crawl-through/GL 89-13) of the Unit 1 "A" ICW discharge header pipe was performed. The inspected pipe started from the discharge end to the 45-degree riser. This area of pipe is underwater (below sea level) adjacent to the discharge canal. During an interview, the diver and pipe inspector reported that roughly 20 percent of the inspected pipe was degraded by corrosion cells. Roughly 50-70 percent of the zinc ribbon which protected the carbon steel pipe was missing from the underwater section. A series of approximately 10 through-wall holes were discovered, starting at about 2 feet upstream the riser pipe. The holes were scattered through an approximate 3-foot pipe run length. All holes were located at the 6 o'clock position of the pipe. Another AR identified a similar amount of degradation in the Unit 1 "B" ICW discharge header. An engineering change replaced the degraded piping. Corrective actions from the associated root cause investigation improved underwater inspection procedures to prevent future undetected degradation of below sea level ICW piping.

- In September 2014, during repairs of the Unit 1 C ICW elbow, an internal inspection of the elbow identified two areas for repair. A work order performed the repair.

- In August 2016, diver inspections were performed on the Unit 1 "B" ICW discharge header. Fouling ratings (FR) were determined based on guidance from the Naval Ships' Technical Manual, S9086-CQ-STM-010 (Reference 1.6.38), Revision 5. The diver determined the severity of marine growth within the pipe met an FR20 rating (advanced slime) and the snorkel portion met an FR50 rating (calcerous fouling in the form of barnacles less than ¼-inch in diameter or height). The diver pressure washed the interior to remove the slime and barnacle growth. Due to zero visibility conditions, the diver performed a thorough tactile inspection of the piping. The diver did not discover any gouges, sharp edges, rough patches, or other indications of damage or coating loss. In another portion of the pipe where visibility was possible, no damage or coating loss was noted. The diver checked the 4 anodes with a tactile inspection and did not identify any deformities or damage. As a result of the inspection, no corrective actions nor recommendations related to aging management were made.

- In December 2015, the ICW piping from the Unit 2 "A" CCW heat exchanger to the temperature control valve was identified as having a number of epoxy patches as a result of previous internal cement liner degradation, primarily due to turbulence-induced erosion due to the orifice and valve. Modifications replaced the flow orifices with a new design which eliminated the turbulent flow erosion mechanism. The work order to refurbish the cement lining with epoxy is scheduled to start in 2021.

- In March 2012, PSL management evaluated the existing condition reports associated with the Unit 1 "A" and "B" discharge headers against significance criteria. A determination was made that this issue met the criteria for performing a technical assessment of reportability based on past operability. The technical assessment determined that unexpected aging effects were identified on the Unit 1 ICW piping in 2012. Internal corrosion was occurring on the Unit 1 ICW piping adjacent to the outfall below sea level on both the A and B trains which resulted in pipe replacement. The previous underwater crawl through pipe inspections were not thorough enough to detect the degradation until significant through wall holes had developed and previous coatings methods were not able to prevent further corrosion. As a corrective action, inspection and coatings procedures were strengthened to prevent future corrosion to progress while unidentified. The inspection specification was updated to clarify that while crawl-through inspections of dry piping are preferred (more reliable) than diving inspections, if diving inspections are used, then an AR shall be generated to track the inspection limitations and results, and System and Component Engineering shall review inspection results via video, audio, or photograph records prior to placing the system back in service. Other corrective actions included establishing a zinc anode replacement based on inspection results, installation of conical orifice plates, mapping of epoxy patches, and clarifying the pipe lining within several engineering documents.
- In February 2015, the Unit "2" B CCW heat exchanger was removed from service after an extensive leak search effort stemming from loss of water level in the CCW surge tank. A pressure test of the shell-side (CCW) revealed three leaking tubes. The as-found inspection of the heat exchanger inlet revealed shells, dirt, and debris inside the tubes (ICW). The Unit 2 "B" CCW heat exchanger was last inspected cleaned, and eddy current tested nearly 11 months earlier during the March/April 2014 during a refueling outage. As a corrective action, the three leak locations were plugged. In addition, several tube locations within the periphery of the 3 leaking tubes were plugged as a preventive measure. A functional shell-side pressure test demonstrated that the mechanical plugs had stopped all leakage and that no additional leak locations were present. The apparent cause for the marine fouling appeared to be due to a decrease in injection from the sodium hypochlorite system. Additional corrective actions included replacing the sodium hypochlorite system piping, performing a metallurgy analysis of the failed CCW heat exchanger tubes, and replacing the tubes.

- In November 2015, a 15-20 gpm leak was identified on the inside elbow of the Unit 2 30-inch ICW header upstream of a temperature control valve and downstream of a flow element and the CCW heat exchanger. The pipe hole was roughly the diameter of a pencil. As corrective actions, a UT examination was performed and a work order performed the pipe repair.
- In June 2017, as a result of troubleshooting a leak in the Unit 2 CCW system, operations identified a CCW to ICW leak in the Unit 2 “B” CCW heat exchanger. An apparent cause analysis identified tubes with marine fouling inside, primarily oyster shells. Considering the sodium hypochlorite system was functioning again, lack of pipe cleaning during the most recent outage was identified as the primary cause of the fouling induced leakage. As a corrective action to prevent future occurrence, the procedures and outage preventive maintenance activities were updated to ensure cleaning of the ICW piping upstream of the CCW heat exchangers and downstream of the strainers.
- In October 2019, during the installation of a new valve the existing flange mating surface had created a leak path for residual water flow. The flange was resurfaced by the coatings team in accordance with station procedures as part of the work order.
- In February 2020, an approximately ½-inch leak, was found on the Unit 2 “A” ICW discharge header piping elbow. A work request and work order resolved the leak by replacing the elbow.
- In April 2020, a leak at a Unit 1 ICW isolation valve and tee connection flange interface was identified. The leak appeared to be due to internal and external corrosion. A UT examination was performed. A work request, work order, and engineering change replaced the piping.

Due, primarily, to the external corrosion on the above-ground ICW system piping, an effort to replace the large-bore, above-ground portions of the SR ICW piping with AL6XN SS was initiated. This will also address internal corrosion concerns identified in the OE listed above.

For Unit 1, the piping between the Unit 1 “B” and “C” ICW pump discharge to the crosstie is currently in the process of being replaced. The piping from the “A” ICW pump discharge to the crosstie is scheduled for replacement during the refueling outage starting in 2021. For Unit 2, an elbow on the “A” train was replaced in 2020. The piping from the “B” and “C” ICW pump discharge to the crosstie is currently in the process of being replaced. The piping from the “A” ICW pump discharge to the crosstie is scheduled for replacement during the refueling outage starting in 2021. The large-bore, above-ground, SR ICW piping replacement is scheduled to be complete prior to the SPEO. With this replacement, a majority of the degradation mechanisms in the OE listed above will be eliminated.

There has been no degradation identified in the underground discharge piping after a large portion of it was replaced in 2012. The underground piping between the intake structure and the CCW building has not experienced the type of degradation identified in the OE for the above ground piping. As a result, there are no plans to replace ICW piping that is underground or below sea-level.

Program Assessments and Evaluations

On November 20, 2015 and October 20, 2017, the NRC completed Post-Approval Site Inspections for License Renewal for PSL Unit 1 and Unit 2, respectively, in accordance with NRC IP71003. With respect to the Intake Cooling Water Inspection Program and the PSPM Program, the NRC inspectors did not identify any findings or violations related to the aging management of the in-scope ICW piping or components. The inspectors determined that the regulatory requirements of 10 CFR 54.37(b) were met, and commitment changes were evaluated and reported in accordance with the applicable requirements. No findings related to the aging management of the in-scope ICW piping or components were identified. On September 30, 2019, the NRC completed an Integrated Inspection at PSL Units 1 and 2, which included and inspection of the ultimate heat sink (UHS). The inspection yielded no findings related to the Intake Cooling Water Inspection Program and the PSPM Program.

The most recent significant inspections are listed below. Any ARs resulting from these inspections are discussed above.

- Unit 1 B-Train ICW Pipe Inspection
- Unit 2 B-Train ICW Pipe Inspection
- Unit 1 as-found CCW Heat Exchanger Inspection Including ECT
- Unit 2 as-found CCW Heat Exchanger Inspection Including ECT

The PSL Open-Cycle Cooling Water System AMP owner interviews performed in November and December of 2020 identified the primary program procedure, recent ICW system inspection reports, relevant ARs, modifications made to the ICW system, and the latest enhancements to the program. In addition, the Long Term Asset Management (LTAM) Plan includes a planned upgrade to the hypochlorite system as well as a planned replacement of the above ground SR ICW piping. The interviews identified self-assessment reports which showed a general readiness for the original plant life extension as well as identified lessons learned from other nuclear plants. One of the areas for improvement for the ICW Inspection Program was to provide a more detailed evaluation of program effectiveness in addressing long-term material condition of the ICW system. Another area for improvement included the need to add specific instructions or reference to inspecting small bore connections, orifices, and thermowells to the ICW internal inspection procedure.

As mentioned earlier, in 2012, an unexpected and significant amount of internal degradation was identified within the underground discharge ICW system piping. In response, the root cause was investigated and corrective actions to improve inspections for the overall program. No significant failures of the underground discharge piping have been identified since. The PSL Open-Cycle Cooling Water System AMP is effective at identifying age-related degradation through periodic inspections and repairs identified degradation prior to component failure. The AMP utilizes the corrective action process to thoroughly evaluate degradation and identify actions to prevent recurrence and incorporate those actions into the program when appropriate.

When recurring internal corrosion or erosion is identified as applicable for an AMP, further evaluation of aging management in accordance with NUREG-2192 is recommended. As evaluated above, internal corrosion has occurred within multiple outages during the evaluated 10-year period and several of these occurrences involved a wall reduction of greater than 50 percent. Therefore, the PSL Open-Cycle Cooling Water AMP will need to manage recurring internal corrosion. One proactive action to reduce the number of internal corrosion issues is to replace the above-ground, large-bore, SR ICW piping with AL6XN SS piping. For the piping that is not replaced, the PSL Open-Cycle Cooling Water System AMP meets the recurring internal corrosion management recommendations from NUREG-2192 as follows:

a) The existing examination methods are sufficient to detect recurring internal corrosion before affecting the ability of a component to perform its intended function. These methods primarily include an internal visual inspection of 100 percent of the large-bore ICW header piping length. The visual inspections are currently augmented with brushing, scraping, and hammer testing as applicable to provide assurance that all internal piping degradation is identified. An enhancement will be created to perform volumetric inspections as applicable for areas where visual inspection alone is not adequate or as needed to determine the extent of degradation

b) The existing ICW header inspections are 100 percent visual and are performed at an interval of every 2 refueling outages. When degradation is identified, it is repaired during the same refueling outage. This provides reasonable assurance that all degradation is identified along the ICW header length and that pressure boundary integrity will be maintained until the next inspection.

c) The existing inspection specification provides instructions for documenting inspection results within an Inspector's Report attached to an AR. The specification also provides instructions for the system engineer to map and trend the locations of patches, epoxy, or cement, within the ICW piping. The trending of the inspection parameters/results (e.g., repair locations) provides reasonable assurance that recurring internal corrosion will remain adequately managed.

d) Inspections of components that are buried, underground, or submerged are conducted per the same inspection specification, procedure, and preventive maintenance activities and personnel have been able to perform internal inspections of these sections of ICW piping. The implementation of the existing inspection activities provides reasonable assurance that recurring internal corrosion of the buried, underground, or submerged ICW system components will be adequately managed.

e) The PSL Open-Cycle Cooling Water System AMP uses system instrumentation and/or performance monitoring to identify leaks in involved buried, underground, or submerged ICW piping components. When leaks are identified, an AR is initiated to determine the cause, extent of degradation, and initiate corrective actions. Using instrumentation and/or performance monitoring to identify leaks and adjusting inspections to proactively identify leaks on other susceptible piping provides reasonable assurance that recurring internal corrosion of the buried, underground, or submerged ICW system components will be adequately managed.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL ICW Inspection AMP were identified.

The PSL Open-Cycle Cooling 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 PSL Open-Cycle Cooling Water System 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.2.3.12 Closed Treated Water Systems

Program Description

The PSL Closed Treated Water System AMP, previously known as the Chemistry Control Program – Closed-Cycle Cooling Water System Subprogram, 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 managing aging of the Component Cooling Water (CCW), Emergency Diesel Generator Cooling Water (EDGCW) Systems, and the portion of the Unit 1 of the Turbine Cooling Water (TCW) System that is required to cool the 1A and 1B air compressor components.

The PSL 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. Molybdate-based inhibitors are used for the CCW, and the TCW systems, and nitrite-based inhibitors are used for the EDGCW system.

To prevent loss of material and cracking due to corrosion and SCC, the PSL Closed Treated Water System AMP periodically monitors the closed cooling system chemistry to verify it is being maintained within specified limits. The parameters monitored include pH, specific conductivity, sulfate, chloride, molybdate/nitrite, iron, copper. The acceptable range of values for these parameters are in accordance with the EPRI TR-3002000590 (Reference 1.6.39) 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 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.

Extended Power Uprates (EPUs) for Units 1 and 2 were implemented in 2012. Both the percentage of uprate and the wattage increase were similarly rated. There has been no OE that identified any closed treated water systems which had more frequent or longer out-of-spec water chemistry conditions. Likewise, the acceptable range of values for the parameters shown in the implementing document are identical between Units 1 and 2. Therefore, the differences between the Units are minimal.

NUREG-2191 Consistency

The PSL Closed Treated Water Systems AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M21A, “Closed Treated Water Systems” as modified by SLR-ISG-2021-02-Mechanical, Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance.

Exceptions to NUREG-2191

None.

Enhancements

The PSL Closed Treated Water System 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
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 on the internal surfaces exposed to the treated closed recirculating cooling water.
3. Parameters Monitored or Inspected	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 on the internal surfaces exposed to the treated closed recirculating cooling water.
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. When opportunistic visual inspections are conducted while the system boundary is open, they 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: o 20 percent of the population (defined as components having the same material, water treatment program, and aging effect combination) OR; o A maximum of 19 components per population at each unit, since PSL is a two-Unit plant.

Element Affected	Enhancement
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 report and evaluate any detectable loss of material, cracking, or fouling associated with the surfaces exposed to the treated closed recirculating cooling water per the PSL corrective action program.
7. Corrective Action	Ensure that the following additional inspections and actions are required if a post-repair/replacement inspection or subsequent inspection of surfaces exposed to the treated closed cooling water environment fails to meet acceptance criteria: o The number of increased inspections is determined in accordance with the PSL 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. o 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. o Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. Since PSL is a two-Unit site, the additional inspections include inspections at both Units with the same material, environment, and aging effect combination. o 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 PSL 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 SS 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, PSL updates the governing chemistry procedure to ensure the latest guidelines are being followed. This includes the latest recommendations for corrosion inhibitors.

Plant Specific Operating Experience

In 2012, Unit 2 CCW B Heat Exchanger discharge header drain valve was found to be leaking. Metallurgy analysis results indicated MIC was the driving mechanism of the leak. Corrective action in accordance with EPRI guidelines for a bacteria-related issue resulted in the addition of a biocide to the system. Flushing during biocide injection was performed at locations susceptible to stagnation. Based on the OE from the Unit 2 CCW MIC related leak, biocide treatment was also performed in Unit 1 CCW system in 2013. Similarly, flushing during biocide injection was performed at locations susceptible to stagnation.

In 2017, a determination was made that adequate corrosion protection of the CCW, and TCW systems could be maintained without the addition of sodium nitrite. Discontinuing nitrite addition reduced the cost of maintaining chemistry in these systems.

In 2017, enhancements were made to the microbiological activity controls in the site closed cooling water chemistry programs in accordance with material presented by EPRI. However, in 2018, routine microbiological testing of the CCW, TCW, and EDGCW systems was stopped consistent with the EPRI TR-3002000590 based on elevated system temperatures, elevated system pH, and the presence of borate. Additionally, with the exceptions detailed above in 2012 and 2013, long-term chemistry trends performed between 2005 to 2018 indicated that there was no biological activity in these systems providing addition support to stop routine MIC testing.

Additionally, the Unit 1 TCW chemistry trends from July 2017 to December 2017 indicated that system chemistry was being impacted by dilution from system in-leakage. This dilution of the corrosion inhibitors increased the frequency at which batch corrosion inhibitor additions were required. A TCW leak on the generator hydrogen coolers was identified as the most likely the cause of the elevated system leakage rates, and thus the most likely cause of the observed corrosion inhibitor dilution. Repair of the TCW leak was performed under a WO, and the issue was mitigated.

In 2019, a Level 1 Assessment was performed to evaluate the effectiveness of transitioning CCW and TCW to a molybdate program and discontinuing nitrite additions. Upon reviewing trends for corrosion products versus nitrite concentration from January of 2016 to March of 2019, there were no adverse impacts identified. Therefore, the CCW and TCW were transitioned to a molybdate program with no adverse impact on system health based on corrosion product concentrations.

Program Assessments and Evaluations

In 2010, a self-assessment was performed to identify areas that were not completed for PSL LR commitments. There were no commitments regarding the PSL Closed Treated Water System AMP, and no deviations were identified.

In 2015, the NRC completed a post-approval site inspection for License Renewal for Unit 1 in accordance with NRC IP71003. Based on the inspection samples selected for review, no findings were identified regarding the PSL Closed Treated Water System AMP. The inspectors determined that PSL fully established the required AMPs, and time-limited aging analyses to manage the aging effects of in-scope SSCs through the PEO of Unit 1.

In 2016, a focused self-assessment was performed. The self-assessment included corrective actions associated with the EDGCW. The specific reagent used for the EDGCW systems was not identified in the implementing document for the PSL Closed Treated Water System AMP. The implementing document was updated to identify Borate as the corrosion inhibitor which is credited as a biocide.

In October 2017, the NRC completed a Post-Approval Site Inspection for License Renewal for Unit 2 in accordance with NRC IP71003. The NRC inspectors did not identify any findings regarding the PSL Closed Treated Water System AMP and determined that aging management activities were consistent with licensing basis documents and program procedures.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Closed Treated Water Systems AMP were identified. However, an enhancement was made for additional personnel to become qualified to the plant's Aging Management Program Owner mentor guide.

The PSL Closed Treated 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 PSL Closed Treated Water System 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.2.3.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

Program Description

The PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is an existing AMP that was evaluated as a portion of the PSL Structures Monitoring (Section B.2.3.33) AMP in the initial license renewal application. The PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is evaluated separately in the subsequent license renewal application and it is compared to the NUREG-2191, Section XI.M23 program.

The PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) 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 SR 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 PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) 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, as well as 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 B30.2-2005, "Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)."

NUREG-2191 Consistency

The PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, with enhancements, will be consistent without exception to the 10 elements of 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 PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems 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	Update the PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP implementing procedure to specify the NUREG-0612 load handling systems.
4. Detection of Aging Effects	Update the PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems implementing procedure to state that, for the in-scope systems that are infrequently in service, such as the containment polar cranes, periodic inspections are performed once every refueling cycle just prior to use. Also update the PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems implementing procedure and inspection procedures to state their respective visual inspection frequencies required by ASME B30.2-2005. According to ASME B30.2-2005, inspections are performed within the following intervals: • "Periodic" visual inspections by a designated person are required and documented yearly for normal service applications • 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 ASME B30.2-2005 paragraph 2-2.1.3 (i.e., periodic inspection). Also update the governing procedure to ensure that the inspection procedures for the individual load handling systems are clearly identified and referenced.
6. Acceptance Criteria	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 ASME B30.2-2005. This ensures that the correct acceptance criteria and corrective actions are used.
7. Corrective Actions	Update the governing procedure to state that repairs made to NUREG 0612 load handling systems are performed as specified in ASME B30.2-2005. This ensures that the correct repairs are performed when required.

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. OE 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

Several areas of rust were found on the Unit 2 Turbine Building Gantry Crane (200-ton). Recommended corrective actions included cleaning, inspection, and coating of affected areas prior to the next outage. An evaluation determined that the degradation did not impact the CLB function of the crane. A work order was initiated to complete the repairs.

Several rail hold down clip nuts on the east rail of the Unit 2 Turbine Building Gantry Crane (200-ton) were found to be severely corroded with material loss. Corrective actions were recommended to replace nuts, and replace studs if needed, as well as recoat. An evaluation determined that the degradation did not impact the CLB function of the crane. A work order was initiated to complete the repairs.

Program Assessments and Evaluations

Individual inspection forms are completed for Structures Monitoring Program inspections which include the inspection activities for load handling systems. PM work orders schedule the inspections. Repairs are completed using work orders as needed under the corrective action process. These inspections record conditions requiring evaluation or corrective action by building and status of the corrective action implemented for each. The PSL Structures Monitoring AMP (Section B.2.3.33) contains an overview of these inspections.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP were identified.

The PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) 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 PSL Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems 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.2.3.14 Compressed Air Monitoring

Program Description

The PSL Compressed Air Monitoring AMP is an existing AMP which monitors moisture content and contaminants in instrument air (IA) and will perform opportunistic visual inspections of internal surfaces for loss of material. The following systems are in scope for the PSL Compressed Air Monitoring AMP:

- Instrument Air sub-system of the Compressed Air System
- Diesel Air Start sub-system of the Emergency Diesel Generator System

The PSL Compressed Air Monitoring AMP manages components which supply IA to air operated valves (AOVs) in the main steam and ventilation systems, IA to the main steam isolation valve accumulators, IA to the containment isolation system, IA to the Unit 2 main feedwater isolation valve actuator accumulators, IA for the bubbler level system in the boric acid makeup tanks; and starting air to the emergency diesel generators.

No portion of the miscellaneous bulk gas systems is required to be included in the scope of the PSL Compressed Air Monitoring AMP.

The PSL Compressed Air Monitoring AMP includes preventive monitoring of water (moisture), and other contaminants (particulate size and hydrocarbon content) to keep within specified limits.

The PSL 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 are managed by the PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.3.24) AMP.

The PSL 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 PSL Compressed Air Monitoring AMP is based on relevant aspects of the PSL response to NRC GL 88-14 and INPO SOER 88-01. The PSL 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 PSL Compressed Air Monitoring AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M24, "Compressed Air Monitoring".

Exceptions to NUREG-2191

None.

Enhancements

The PSL Compressed Air Monitoring 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	• Compile a governing program procedure for the PSL 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.
3. Parameters Monitored or Inspected	• Update the air quality sampling and/or governing procedure to discuss performing opportunistic visual inspections of accessible internal surfaces for signs of corrosion and abnormal corrosion products that might indicate a loss of material within the system.
4. Detection of Aging Effects	• Update pertinent documents to include inspections of internal air line surfaces downstream of the instrument air dryers and emergency diesel generator air start dryers with maintenance, corrective, or other activities that involve opening of the component or system. • Update pertinent documents to include 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. • Include requirements for better long term trending of negative trends, more thorough documentation, and proactive aging management. • Consider ASME OM-2012, Division 2, Part 28 for monitoring and trending guidance.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

- 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 PSL response to NRC IN 2008-06, PSL performed an evaluation of impact to Operations and it was determined that loss of instrument air is covered in both initial and requalification training for Operations. An additional evaluation determined that this event was caused by poor construction techniques and that there was no impact on Operations Training due to this event.

- At Point Beach Nuclear Plant (PBN), 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). 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.

  PSL has quarterly sampling of the instrument air system. There are requirements for purging the sample point for approximately 5 minutes prior to sampling and the instrument air dryer and filter packages are designed to remove all particulate matter over 0.9 microns in size.

- In November 2011 at PBN, many of the Diesel Air system check valves had PMs developed to inspect and replace parts to allow rebuilding of the valves, as required, on a six-year frequency, based on a single check valve sticking open during in-service testing.

  The equivalent PSL diesel air check valves are not the same manufacturer as those used at PBN, have not experienced issues with sticking open, and currently have existing preventive maintenance activities to inspect them on a twelve-year frequency; therefore, no updates to PSL were required.

Plant Specific Operating Experience

- Action Requests (ARs)
  - There are many examples of ARs written regarding issues with the instrument air dryers, such as degrading trends in dew points and failure of instrument air dryer components. These ARs demonstrate that the PSL Compressed Air Monitoring AMP performs periodic maintenance and monitoring of the IA system to provide reasonable assurance that high quality air is being delivered to critical plant components.
- System/Program Health Reports
  - Instrument and Service Air System Health: Currently Green; however, the section for Maintenance Rule is White on Unit 2 for maintenance related to the 2C IA compressor, the section for System Performance is White on both Units 1 and 2 for dryers not maintaining dewpoint below required performance criteria, and the section for Maintenance and Material Condition is Yellow for clogged drains on the 2A IA compressor moisture separator and mechanical failure of a Unit 2 2D IA compressor blowdown valve. Enhanced monitoring and additional actions are noted to have been initiated to address the negative dewpoint trend. Prior to this, and dating back to 2015, the instrument and service air system has been in overall Green or White Status.
  - Emergency Diesel Generator System (includes Diesel Starting Air): The emergency diesel starting air system does not have its own system health report; therefore, the emergency diesel generator system health reports were reviewed to assess system health and performance. The following are the health status for the EDG system for the past five years:
    - White since the fourth quarter of 2019
    - Red in the third quarter of 2019
    - Green from the second quarter of 2019 to the third quarter of 2018
    - White from the second quarter of 2018 to the third quarter of 2015
    - Green for the first and second quarters of 2015

    Items related to the diesel starting air system portion mainly involved obsolescence and needed replacement of the starting air dryers for Unit 1 (noted as not applicable to Unit 2). Funding has been approved in the fourth quarter of 2020 and creation of an engineering change for replacement of the EDG startup air dryers is pending for Unit 1.

Program Assessments and Evaluations

- A 2009 self-assessment documented the IA particulate monitoring results (past two years), IA dew point monitoring results (past two years), IA hydrocarbon monitoring results (past two years), and system health reports for the IA system (last two). In addition, the status of SOER 88-1 recommendation 5 was provided. The SOER 88-1 review concluded that periodic maintenance and monitoring of the instrument air system provided evidence that the preventive maintenance program ensures that high quality air is being delivered to critical plant components. In addition, the PSL preventive maintenance program replaces filters and desiccant material, as well as performs IA dryer maintenance on a regularly scheduled basis.

- A 2007 effectiveness review selected SOER 88-1, Instrument Air System Failures, to evaluate continued satisfactory implementation of the recommendations identified in SOER 88-1. System issues are typically the result of excessive moisture and contamination. The PSL IA dryers include inlet and outlet filters that are required to maintain low particulates and moisture content of the compressed air supplied to critical components. Periodic maintenance of the IA compressors and dryers is performed. In response to GL 88-14, PSL established periodic monitoring of the air quality downstream of the instrument air dryers. This includes monitoring of dewpoint and hydrocarbons. This periodic maintenance and monitoring of the IA system provides reasonable assurance that high quality air is being delivered to critical plant components. No corrective actions were identified as a result of this effectiveness review.

- AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5 year effectiveness review was completed in January 2021 and no findings were identified related to the PSL Compressed Air Monitoring AMP.

The PSL 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 PSL Compressed Air Monitoring 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.2.3.15 Fire Protection

Program Description

The PSL Fire Protection AMP is an existing AMP, formerly a portion of the PSL 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). The PSL 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, as well as periodic visual inspection and functional tests of fire-rated and in scope exterior non-fire rated doors so that their operability is maintained. The PSL Fire Protection AMP also requires periodic visual inspection of other passive fire protection features credited for the Fire Protection Program like oil collection dikes and curbs. The PSL Fire Protection AMP also includes periodic inspection and testing of the halon fire suppression systems.

With respect to preventive actions, PSL 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, delamination, separation, 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, cracking, or elastomer degradation as applicable on fire damper assemblies;

d) No visual indications of missing parts, holes, and wear; and

e) No conditions in the functional tests of fire and non-fire rated exterior doors (i.e., the door swings easily, freely, and achieves positive latching assisted or unassisted).

Periodic inspections and testing of the halon fire suppression 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 in accordance with the plant's NRC-approved fire protection program or at least once every refueling outage. Visual inspections on fire-rated structures (fire barrier walls, ceilings, and floors), combustible liquid spill retaining features (oil collection dikes and curbs), fire-rated assemblies, and on the fire damper assemblies are conducted at a frequency in accordance with the plant's NRC-approved fire protection program. Periodic visual inspections are performed and functional tests are conducted on fire doors and their closing mechanism and latches are verified functional at a frequency in accordance with the plant's NRC-approved fire protection program.

The results of inspections and functional testing of the in-scope fire protection equipment are collected, analyzed, and failed or degraded components are 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 PSL corrective action program is utilized to drive improvement. During the inspection of penetration seals, if any sign of abnormal degradation is detected within the sample, the inspection sample size is expanded, in accordance with the approved PSL fire protection program, to include an additional 10 percent of each type of sealed penetration.

NUREG-2191 Consistency

The PSL Fire Protection AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M26, “Fire Protection”.

Exceptions to NUREG-2191

None.

Enhancements

The PSL 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 and loss of strength such as cracking, seal separation from walls and components, separation of layers of material, rupture, and puncture of seals.

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 subliming, cementitious, and silicate materials used in fireproofing and fire barriers will be inspected for loss of material, change in material properties, and cracking/delamination.
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 (e.g., general, pitting, or crevice corrosion), cracking, or elastomer degradation (e.g., hardening, loss of strength, or shrinkage) as applicable to the fire damper assembly is unacceptable.
5. Monitoring and Trending	Enhance plant procedures to require projection of identified degradation to the next scheduled inspection for all monitored fire protection SSCs, where practical.
5. Monitoring and Trending	Enhance plant procedures to require that projections are 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.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

- 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.

- 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 PSL is managing aging effects associated with the PSL Fire Protection AMP.

- During an inspection a fire damper was discovered to have two curtains with broken springs (4 total). The broken springs were replaced.

- Several exterior doors were added to the fire protection program as a part of the plant's transition to 10 CFR 50.48(c) licensing basis. Initial inspections of these new fire protection features identified some of them as degraded. A door and frame were identified as rusted on the outside and inside. Another door was also identified as having rust at the top and bottom. Repairs were made to both doors and the frame.

- During an inspection local distortion was discovered on a radiant energy shield. An engineering evaluation was performed to determine if the distortion compromised the radiant energy shield's intended function. Based on the evaluation the radiant energy shield was repaired.

- During a penetration seal inspection, shrinkage and cracking at a penetration were discovered. The penetration was a through floor penetration and must have at least 6 inches of penetration seal material located within the plane of the fire barrier. The depth of the elastomer seal material was verified in the field as having a depth of at least 9 inches. The surface of the elastomer seal material was observed to have some surface cracking that did not penetrate into the elastomer except along the edges and corners of the concrete curb of the penetration. There was no cracking, shrinkage, or degradation of the elastomer along the periphery of the penetrating items (cable tray and conduits). The following shrinkage gaps were observed along the periphery of the concrete penetration curb: South East Corner, 3/16-inch, North East corner, 3/16-inch and South West corner, 3/32-inch. A 1/8-inch probe could also be inserted along the East edge of the penetration to a depth of 9 inches, indicating an elastomer depth of 9 inches. There were no gaps, cracks, or evidence of shrinkage between the cable tray and the elastomer or the conduits and the elastomer.

  An hourly fire watch patrol was established and the voids along the periphery of the penetration were filled with elastomer.

- During the course of daily operations, the hinge on a door was identified as being loose, causing the door edge to catch the frame prior to closing completely and latching. The door would latch only if manually pushed closed, rendering it more susceptible to being left unlatched. The door hinge was repaired and the door alignment adjusted to prevent catching.

- During the course of daily operations, the seal on a door was identified as being loose and not adhering to the door jamb surface. The seal was replaced.

- During an inspection a 6-inch penetration was documented as having delamination between the elastomer and the existing pipe sleeve that was approximately 300 degrees around the penetration. Inspection from the pipe penetration side identified minor delamination, but nothing that compromised the penetration. The delamination was filled with the appropriate penetration seal material.

- During an inspection a fire door was found to be crooked in its door frame. The door gap was inconsistent and exceeded allowable tolerance. The door was adjusted until the gap was within allowable tolerances.

<u>Program Assessments and Evaluations</u>

- In 2010, a self-assessment was performed to identify items that were not completed for the PSL LR commitments. No items were found in the PSL Fire Protection AMP, and no license renewal commitments had been changed since the SER was issued.

  The review also included verification that licensing activities associated with the renewed operating licenses were being met indicating readiness for the subsequent IP71003 Phase I and II inspection.

- In 2015, a focused self-assessment for Unit 1 was performed to identify actions required to achieve readiness for the NRC License Renewal Implementation IP71003 Phase II Inspection. This review included an evaluation of the impacts of the plant’s transition to a 10 CFR 50.48(c) licensing basis on the requirements of 10 CFR 54.37(b). Because the transition of the licensing basis was not complete at the time the 10 CFR 54.37(b) review was performed, no changes were made. Another AR was written to track the incorporation of changes to LR when the transition to the new fire protection licensing basis was complete.

- In 2015, an assignment to an AR was written to track the completion of the transition of PSL Unit 1 to a new fire protection licensing basis. Other assignments to the AR would then direct actions to provide reasonable assurance that any new SSCs required because of the licensing basis change were included in the PSL Fire Protection AMP for Unit 1. The assignments were completed in 2017.

- The NRC completed a post-approval site inspection for License Renewal for Unit 1. Based on the inspection sample selected for review, no findings, or violations of more than minor significance were identified. The inspectors determined that PSL fully established the required AMPs and time-limited aging analyses to manage the aging effects of in-scope SSCs through the PEO of Unit 1, with the exception of an Unresolved Item. The Unresolved Item was associated with the implementation status of the various commitment items that required follow-up during future license renewal inspections to obtain reasonable assurance that the license renewal commitments were met, and that the aging effects of affected SSCs would be managed during the PEO. Only minor observations regarding inconsistencies in procedures were identified for the PSL Fire Protection AMP, which were documented in an AR and completed a month later.

- In 2017, a focused self-assessment for Unit 2 was performed to identify actions required to achieve readiness for the NRC License Renewal Implementation IP71003 Phase II Inspection. The assessment determined that License Renewal implementation was on track but identified some existing items that needed to be closed prior to the August 28, 2017

NRC Phase II inspection. Resolution of the items were tracked and resolved through the corrective action program. The assessment report identified some recommended changes to the PSL Fire Protection AMP, though these were mostly editorial or to provide additional clarification. The report also identified that an AR was tracking the completion of the plant's transition to a new fire protection licensing basis. Upon completion of the transition, newly identified SSCs required for fire protection were added to the PSL Fire Protection AMP per 10 CFR 54.37(b) as applicable.

- The NRC completed a post-approval site inspection for License Renewal for Unit 2. Based on the sample selected for review, the inspector determined that commitments, license conditions, and regulatory requirements associated with the renewed facility operating license were met. The inspector also determined that the licensee had administrative controls in place to ensure completion of pending actions scheduled both prior to and during the PEO.

- In April 2019, a Routine Work Tracker (RWT) was generated to track completion of LR AMP Effectiveness review for PSL by the individual program engineers and to update the AMP Basis documents accordingly.

  In October 2019, an effectiveness review and assessment on Elements 4, 7 and 10 of the PSL Fire Protection AMP were performed. No findings were identified.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Fire Protection AMP were identified.

The PSL 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 PSL 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 PSL 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 1.6.40).

PSL 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 provide reasonable assurance 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 AMPs supplement the PSL Fire Water System AMP in managing aging of the fire water system components. The PSL Bolting Integrity (Section B.2.3.9) AMP will manage loss of preload, cracking, and loss of material for fire water system closure bolting. The PSL Buried and Underground Piping and Tanks (Section B.2.3.27) AMP is used to manage aging of the external surfaces of buried and underground fire water system piping. The PSL External Surfaces Monitoring of Mechanical Components (Section B.2.3.23) AMP is used to manage aging of the above-ground fire water system piping surfaces. The PSL Selective Leaching (Section B.2.3.21) 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 PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.3.28) AMP is used to manage aging of all internal surface coatings applied to fire water system components. The PSL Structures Monitoring (Section B.2.3.33) AMP manages aging of the City Water Storage Tank (CWST) caulking.

Fast-response and traditional sprinkler heads are either replaced or tested in accordance with NFPA 25 prior to exceeding their 20-year or 50-year service life, respectively. A representative sample of sprinklers from one or more sample areas are removed and tested at an off-site laboratory per the guidance of NFPA 25. If the sprinkler heads are not replaced, the required testing will be repeated at 10-year intervals. Several aging sprinkler heads have already been replaced per preventive maintenance activities.

Fire water systems are regularly flushed to remove blockage and obstructions such as corrosion products and sediment. The PSL Fire Protection Plan outlines the procedures and surveillance intervals associated with periodic flushing:

- Yard fire hydrants are flow checked every 12 months to assure that the hydrants are not isolated or blocked. The fire hydrants and underground fire water main are flow flushed at least once every 12 months and flow tested every 3 years. The CWSTs 1A and 1B are internally inspected every 5 years.

- Intervals for flushes, flow/pressure/pump capacity tests of deluge systems, sprinklers, and spray nozzles are performed at 6-month, 12-month, or 18-month frequencies, depending on the system.

- All fire hose stations are flow tested/flushed at least every three years, although some hoses and stations are tested more frequently.

As a preventive or aging mitigation measure, the fire water system at PSL is filled with water classified as “raw water – city water.” This water is potable water. The water has been rough filtered to remove large particles. City water has been purified but conservatively classified as raw water for the purpose of performing aging management reviews even though it is clean and free of contaminants compared to lake or river water used in fire protection systems at other plants. The quality of the water minimizes loss of material, as evidenced by PSL’s operating and maintenance experience. A fire protection system annual flush is credited for ensuring the system is clear of scale, debris, and foreign material. As another preventive measure, the CWSTs have caulking applied to the tank-to-concrete interface.

To address potential loss of material, cracking, and flow blockage, the PSL Fire Water System AMP monitors several fire water system parameters. 18-month fire pump capacity testing is performed and 12-month fire water system flow testing is performed to provide reasonable assurance that the fire water system can maintain required system pressures, flow rates, and internal conditions (i.e., no fouling or sediment blockage). These tests also provide reasonable assurance that the electric motor-driven fire pumps are performing adequately and meet the requirements specified in fire protection design basis document. Occurrences of pipe/component leakage are also visually identified during these tests. Although some fire protection and/or service water piping is internally coated with a cementitious coating, visual examinations of such cementitious coatings (for indications of loss of material or cracking) are not performed by the PSL Fire Water System AMP, but rather those coatings are managed by the PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.3.28) AMP. No cementitious (concrete) piping is used in the PSL fire water system and applicable portions of the service water system; therefore, no visual inspection of cementitious material is performed by the PSL Fire Water System AMP.

The detection of age-related degradation on external surfaces is determined by visual examination. Surfaces of components and structures are examined for coating degradation (cracks, flaking and peeling, bubbling), rust, missing hardware, damage, deterioration, leakage, or corrosion. Functional testing and flushing of the systems clear away internal scale and corrosion products that could lead to blockage/obstruction of the system. Visual examinations of breached portions of the system also verify unobstructed flow and integrity of the piping/components. Continuous fire water system pressure monitoring is performed and low-pressure alarms alert the operators to abnormal system conditions or leaks. Therefore, loss of system pressure is immediately detected and corrected when acceptance criteria are exceeded. Additionally, periodic functional testing, internal inspections, and wall thickness evaluations of selected portions of the system provides reasonable assurance that corrosion and biofouling are not occurring to an extent that an intended function would be compromised.

The CWSTs are externally inspected annually and internally inspected and volumetrically (UT) examined on a 5-year interval, which includes UT examination of the tank bottoms. These wall thickness examinations will also examine the CWST bottom surfaces in accordance with the NUREG-2191, Table XI.M29 1. Specifically, for each 10-year period starting 10 years before the SPEO, a volumetric inspection will be required to be performed from the inside surface of the tanks. The new tank bottom thickness inspections will use a low-frequency electromagnetic testing (LFET) technique and, as necessary, follow-up ultrasonic examinations. Any regions below nominal plate thickness will have a follow-up ultrasonic thickness reading. If there are areas of significant loss of material that could impact the pressure boundary function, future ultrasonic thickness measurements and trending will be performed.

Results from the various surveillances are evaluated per the respective procedures. Any degradation identified by visual/volumetric inspections or flushes/flow testing is reported, evaluated, and corrected through the PSL corrective action program. Acceptance criteria for observed degradation, flow obstruction, discharge flow/pressures, or minimum wall thickness are defined in the PSL Fire Water System AMP procedures used to perform the respective inspections and tests.

NUREG-2191 Consistency

The PSL Fire Water System AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M27, “Fire Water System”.

Exceptions to NUREG-2191

None.

Enhancements

The PSL 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, as well as state which procedures perform surface examinations or ASME Code, Section XI, VT-1 visual examinations for identifying SCC of copper alloy (>15% Zn) valve bodies, nozzles, and strainers. 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. The 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% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 19 components per population at each Unit is inspected. Where practical, the inspections will focus on the bounding or lead components most susceptible to aging.
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 inspection/testing procedures and create new procedures to incorporate the surveillance requirements stated in NUREG-2191, Section XI.M27, Element 4 and Table XI.M27-1, which are based on NFPA 25, 2011 edition. This includes testing or replacement of fast-response and traditional sprinkler heads that have been in service for 20 or 50 years, respectively, in accordance with NFPA 25.

Element Affected	Enhancement
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 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. Results of flow testing (e.g., buried and underground piping, fire mains, and sprinklers/spray nozzles), flushes, and wall thickness measurements are monitored and trended by either the Engineering or the 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 PSL 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.

Element Affected	Enhancement
5. Monitoring and Trending	Update spray and sprinkler system flushing procedures to enable trending of data. Specifically, the existing flushing procedures will be revised to document and trend deposits (scale or foreign material). Recommended methods for trending deposits may include the following as feasible: • Inspectors will take photographs of deposits. • Inspectors will measure the weight of the deposits. • Inspectors will measure elapsed time taken to complete a flush (i.e., the time required for the flushing water to turn an acceptable color). The documentation above will be maintained by the AMP owner for comparing and trending inspection/test results. Existing flushing procedures, as well as new flushing procedures, will include steps to compare the amount of deposits to the previous inspections' results, and if the trend is negative or if the projected solids for the next inspection/test/flush are anticipated to exceed an acceptable amount that would impact the system intended function, then the PSL Corrective Action Program will be utilized to drive improvement. Additionally, identified deposits will be evaluated for potential impact on downstream components, such as sprinkler heads or spray nozzles.
6. Acceptance Criteria	Update the governing AMP procedure to state identified wall loss greater than the manufacturers tolerance will be entered into the CAP process for engineering evaluation.
6. Acceptance Criteria	Update the governing AMP procedure to point to the inspection procedures which inspect the wall thicknesses and compare wall loss to the manufacturer's tolerance.
6. Acceptance Criteria	Update the governing AMP procedure to state that internal inspection, flow testing, and flushing procedures/PMRQs must demonstrate that no loose fouling products exist in the systems that could cause flow blockage in the sprinklers or deluge nozzles.

Element Affected	Enhancement
7. Corrective Actions	Update the governing AMP procedure and respective pipe inspection procedures to state that if an obstruction inside piping or sprinklers is detected during pipe inspections, the material is removed and the inspection results are entered into the PSL 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 Annex 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 PSL corrective action program. If a failure occurs (e.g., a through-wall leak or blockage impacting operability), the failure mechanism shall be identified and used to determine the most susceptible system locations for additional inspections, including consideration to the other Unit systems as driven by the corrective action program. When piping is replaced prior to failure, due to concerns with wall thinning or blockage, inspections are considered for similar areas of the system to determine the presence and extent of degradation. The implementation of these augmented inspection actions provides reasonable assurance that the fire water system will continue to perform its function adequately through the SPEO.
7. Corrective Actions	Update the existing flow test procedure and the existing deluge system flush/test procedure enhanced with new main drain tests 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 will be conducted. The number of increased tests is determined in accordance with the PSL 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 will be conducted to determine the further extent of tests. Since PSL is a two-Unit site, additional tests include inspections at both of the Units with the same material, environment, and aging effect combination.

Element Affected	Enhancement
7. Corrective Actions	Update the primary program documents and procedures and applicable preventive maintenance activities to state that, as a contingency, if degradation mechanisms such as MIC, erosion, or recurring loss of material due to internal corrosion were to occur, 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 PSL 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 PSL 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. That 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 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.

The following table provides additional detail on the enhancements based on NUREG-2191 Table XI.M27-1.

Description	NFPA 25 Section	Required Enhancements
Sprinkler Systems		
Sprinkler inspections	5.2.1.1	The relevant procedures and preventive maintenance activities are currently performed either on a 6-month, 12-month, or refueling outage interval (every 18 months), which meets the interval requirements of NUREG-2191 Table XI.M27-1 Note 10. The relevant procedures and preventive maintenance activities will be enhanced to incorporate the requirements of NFPA 25 Section 5.2.1.1 to ensure that sprinklers are visually inspected from the floor level and meet the acceptance criteria, which include no signs of leakage, corrosion, foreign materials, paint (unless painted by manufacturer), physical

Description	NFPA 25 Section	Required Enhancements
		damage, loading, and loss of fluid in glass bulb heat responsive elements. Additionally, sprinklers shall be installed in the correct orientation (e.g., upright, pendent, or sidewall). Any sprinkler that does not meet these criteria shall be replaced. Note: The acceptance criteria related to glass bulb heat responsive elements only apply to the procedures that inspect closed head sprinklers (wet system and pre-action system), rather than open head nozzles. The documentation above will be maintained by the AMP owner for comparing and trending inspection/test results. 5.2.1.1* Sprinklers shall be inspected from the floor level annually. [See NUREG-2191 Table XI.M27-1 Note 10.] 5.2.1.1.1* Sprinklers shall not show signs of leakage; shall be free of [significant] corrosion, foreign materials, paint, and physical damage; and shall be installed in the correct orientation (e.g., upright, pendent, or sidewall). 5.2.1.1.2 Any sprinkler that shows signs of any of the following shall be replaced: (1) Leakage (2) [Significant] Corrosion (3) Physical damage (4) Loss of fluid in the glass bulb heat responsive element (5)*Loading (6) Painting unless painted by the sprinkler manufacturer 5.2.1.1.3* Any sprinkler that has been installed in the incorrect orientation shall be replaced. 5.2.1.1.4 Any sprinkler shall be replaced that has signs of leakage; is painted, other than by the sprinkler manufacturer, corroded, damaged, or loaded; or is in the improper orientation. 5.2.1.1.5 Glass bulb sprinklers shall be replaced if the bulbs have emptied. 5.2.1.1.6* Sprinklers installed in concealed spaces such as above suspended ceilings shall not require inspection. 5.2.1.1.7 Sprinklers installed in areas that are inaccessible for safety considerations due to process operations shall be inspected during each scheduled shutdown.
Sprinkler testing	5.3.1	Update relevant preventive maintenance activities to incorporate the following sprinkler testing instructions of NFPA 25, Section 5.3.1 subsections. Steps with asterisks have additional clarifying information in NFPA 25, Annex A. The required steps and information are as follows: 5.3.1.1*: Where required by this section, sample sprinklers shall be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing. 5.3.1.1.1: Where sprinklers have been in service for 50 years, they shall be replaced or representative samples from one or more sample areas shall be tested. 5.3.1.1.1.1: Test procedures shall be repeated at 10-year intervals. 5.3.1.1.1.2: Sprinklers manufactured prior to 1920 shall be replaced.

Description	NFPA 25 Section	Required Enhancements
		5.3.1.1.1.3*: Sprinklers manufactured using fast-response elements that have been in service for 20 years shall be replaced, or representative samples shall be tested and then retested at 10-year intervals. 5.3.1.1.1.4*: Representative samples of solder-type sprinklers with a temperature classification of extra high [325°F (163°C)] or greater that are exposed to semi-continuous to continuous maximum allowable ambient temperature conditions shall be tested at 5-year intervals. 5.3.1.1.1.5: Where sprinklers have been in service for 75 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing and repeated at 5-year intervals. 5.3.1.1.1.6*: Dry sprinklers that have been in service for 10 years shall be replaced or representative samples shall be tested and then retested at 10-year intervals. 5.3.1.1.2*: Where sprinklers are subjected to harsh environments, including corrosive atmospheres and corrosive water supplies, on a 5-year basis, either sprinklers shall be replaced or representative sprinkler samples shall be tested. 5.3.1.1.3: Where historical data indicate, longer intervals between testing shall be permitted. 5.3.1.2*: A representative sample of sprinklers for testing per NFPA 25, Section 5.3.1.1.1, shall consist of a minimum of not less than four sprinklers or 1 percent of the number of sprinklers per individual sprinkler sample, whichever is greater. 5.3.1.3: Where one sprinkler within a representative sample fails to meet the test requirement, all sprinklers within the area represented by that sample shall be replaced. 5.3.1.3.1: Manufacturers shall be permitted to make modifications to their own sprinklers in the field with listed devices that restore the original performance as intended by the listing, where acceptable to the authority having jurisdiction. If loose deposits are identified in the piping, and the evaluation determines that the deposits must be removed, then the piping is required to be flushed repeatedly, in accordance with NFPA 25 Annex D.5, until it is determined that either no deposits are left or that the remaining deposits pose no blockage threat. Areas where excessive deposits are found will undergo more thorough volumetric wall testing to ensure minimum wall thickness is met. Note: Several sprinkler head have already been replaced as documented in relevant ARs and preventive maintenance activities.
Standpipe and Hose Systems		
Flow tests	6.3.1	The relevant flow test procedure and preventive maintenance activity are currently performed at a 3-year interval which meets the 5-year interval requirement. The procedure and preventive maintenance activity will be enhanced to ensure the following requirements of NFPA 25, Section 6.3.1 and subsections are met:

<table>
<tr><th>Description</th><th>NFPA 25 Section</th><th>Required Enhancements</th></tr>
<tr><td></td><td></td><td>6.3.1: Flow Tests.

6.3.1.1*: A flow test shall be conducted [at least] every 5 years at the hydraulically most remote hose connections of each zone of an automatic standpipe system to verify the water supply still provides the design pressure at the required flow.

6.3.1.2: Where a flow test of the hydraulically most remote outlet(s) is not practical, the authority having jurisdiction shall be consulted for the appropriate location for the test.

6.3.1.3: All systems shall be flow tested and pressure tested at the requirements for the design criteria in effect at the time of the installation.

6.3.1.3.1: The actual test method(s) and performance criteria shall be discussed in advance with the authority having jurisdiction.

6.3.1.4: Standpipes, sprinkler connections to standpipes, or hose stations equipped with pressure reducing valves or pressure regulating valves shall have these valves inspected, tested, and maintained in accordance with the requirements of NFPA 25, Chapter 13.

6.3.1.5: A main drain test shall be performed on all standpipe systems with automatic water supplies in accordance with the requirements of NFPA 25, Chapter 13.

6.3.1.5.1: The test shall be performed at the low point drain for each standpipe or the main drain test connection where the supply main enters the building (when provided).

6.3.1.5.2: [Not applicable per NUREG-2191 Table XI.M27-1 Note 9, which states that calibration of measuring and test equipment (i.e., pressure gauges provided for flow tests) can conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.]</td></tr>
<tr><td colspan="3">Private Fire Service Mains</td></tr>
<tr><td>Underground and exposed piping flow tests</td><td>7.3.1</td><td>The relevant test procedure and preventive maintenance activity are currently performed at a 3-year interval which meets the 5-year interval requirement. The procedure and preventive maintenance activity will be enhanced to ensure the following requirements of NFPA 25, Section 7.3.1 and subsections are met:

7.3.1*: Underground and Exposed Piping Flow Tests. Underground and exposed piping shall be flow tested to determine the internal condition of the piping at minimum 5-year intervals.

7.3.1.1: Flow tests shall be made at flows representative of those expected during a fire, for the purpose of comparing the friction loss characteristics of the pipe with those expected for the particular type of pipe involved, with due consideration given to the age of the pipe and to the results of previous flow tests.

7.3.1.2: Any flow test results that indicate deterioration of available water flow and pressure shall be investigated to the complete satisfaction of the authority having jurisdiction to ensure that the required flow and pressure are available for fire protection.

7.3.1.3: Where underground piping supplies individual fire sprinkler, standpipe, water spray, or foam-water sprinkler systems and there are no</td></tr>
</table>

Description	NFPA 25 Section	Required Enhancements
		means to conduct full flow tests, tests generating the maximum available flows shall be permitted. Per NUREG-2191 Table XI.M27-1 Note 9, calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.
Hydrants	7.3.2	The relevant test procedures and preventive maintenance activities have fire hydrant flushing (flow check) performed every 12 months which meets the refueling outage interval requirement of NUREG-2191, Table XI.M27-1, Note 10. This test ensures that the hydrants and their respective piping systems are functioning properly. These procedures will be enhanced to clarify the other requirements of the NFPA 25, Section 7.3.2 subsections: 7.3.2.1: Each hydrant shall be opened fully and water flowed until all foreign material has cleared. 7.3.2.2: Flow shall be maintained for not less than 1 minute. 7.3.2.3: After operation, dry barrel and wall hydrants shall be observed for proper drainage from the barrel. 7.3.2.4: Full drainage shall take no longer than 60 minutes. 7.3.2.5: Where soil conditions or other factors are such that the hydrant barrel does not drain within 60 minutes, or where the groundwater level is above that of the hydrant drain, the hydrant drain shall be plugged and the water in the barrel shall be pumped out. 7.3.2.6: [This step is not applicable, since the PSL fire hydrants are not in an area subject to freezing weather.] If loose deposits are identified in the piping, and the evaluation determines that the deposits must be removed, then the piping is required to be flushed repeatedly, in accordance with NFPA 25 Annex D.5, until it is determined that either no deposits are left or that the remaining deposits pose no blockage threat. Areas where excessive deposits are found will undergo more thorough volumetric wall testing to ensure minimum wall thickness is met. Per NUREG-2191 Table XI.M27-1 Note 9, calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.
Fire Pumps		
Suction screens	8.3.3.7	N/A
Water Storage Tanks		
Exterior inspections	9.2.5.5	The relevant preventive maintenance activities perform visual inspections of CWSTs 1A and 1B on a 12-month interval, which meets the refueling outage interval requirements of NUREG-2191, Table XI.M27-1, Note 10. The relevant preventive maintenance activities will be enhanced to clarify the other requirements of NFPA 25, Section 9.2.5.5: 9.2.5.5: Exterior painted, coated, or insulated surfaces of the tank and supporting structure, where provided, shall be inspected annually for signs of degradation.

Description	NFPA 25 Section	Required Enhancements
Interior inspections	9.2.6, 9.2.7	The relevant preventive maintenance activities perform interior inspections of CWSTs 1A and 1B on a 5-year interval, which meets the interval requirements of NFPA 25, Section 9.2.6.1.2. The relevant preventive maintenance activities will be enhanced to clarify the other requirements of NUREG-2191, Table XI.M27-1, and NFPA 25, Sections 9.2.6, 9.2.7, and subsections. Steps with asterisks have additional clarifying information in NFPA 25, Annex A. The required steps and information are as follows: 9.2.6.1.1*: [This step is not applicable since the CWST 1A and 1B have interior coatings, which is a type of corrosion protection.] 9.2.6.1.2: The interior of all other types of tanks [e.g., tanks with internal coatings] shall be inspected every 5 years. 9.2.6.2: Where interior inspection is made by means of underwater evaluation, silt shall first be removed from the tank floor. 9.2.6.3: The tank interior shall be inspected for signs of pitting, corrosion, spalling, rot, other forms of deterioration, waste materials and debris, aquatic growth, and local or general failure of interior coating. 9.2.6.4: Steel tanks exhibiting signs of interior pitting, corrosion, or failure of coating shall be tested in accordance with NFPA 25, Section 9.2.7. 9.2.6.5*: Tanks on ring-type foundations with sand in the middle shall be inspected for evidence of voids beneath the floor. [This inspection can be performed by looking for dents on the tank floor. Additionally, walking on the tank floor and looking for buckling of the floor will identify problem areas.] 9.2.6.6: The heating system and components including piping shall be inspected. 9.2.6.7: The anti-vortex plate shall be inspected for deterioration or blockage. 9.2.7: Tests During Interior Inspection. Where a drained interior inspection of a steel tank is required by 9.2.6.4, the following tests shall be conducted: (1) [Not applicable per NUREG-2191 Table XI.M27-1 Note 4. See below.] (2) [Not applicable per NUREG-2191 Table XI.M27-1 Note 4. See below.] (3) Nondestructive ultrasonic readings shall be taken to evaluate the wall thickness where there is evidence of pitting or corrosion. (4) [Not applicable per NUREG-2191 Table XI.M27-1 Note 4. See below.] (5) Tank bottoms shall be tested for metal loss and/or rust on the underside by use of ultrasonic testing where there is evidence of pitting or corrosion. Removal, visual inspection, and replacement of random floor coupons shall be an acceptable alternative to ultrasonic testing. (6) Tanks with flat bottoms shall be vacuum-box tested at bottom seams in accordance with test procedures found in NFPA 22, Standard for Water Tanks for Private Fire Protection. NUREG-2191 Table XI.M27-1 Note 4 is in regard to NFPA 25 Sections 9.2.6.4 and 9.2.7: When degraded coatings are detected, the acceptance

Description	NFPA 25 Section	Required Enhancements
		criteria and corrective action recommendations in GALL-SLR Report AMP XI.M42 are followed in lieu of Section 9.2.7 (1), (2), and (4). When interior pitting or general corrosion (beyond minor surface rust) is detected, tank wall thickness measurements are conducted as stated in NFPA 25 Section 9.2.7 (3) in the vicinity of the loss of material. Vacuum box testing as stated in Section 9.2.7 (6) is conducted when pitting, cracks, or loss of material is detected in the immediate vicinity of welds. Additionally, per NUREG-2191 Table XI.M27-1, calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements. The relevant preventive maintenance activities, which already perform 5-year tank bottom testing for license renewal, will also be enhanced to state that CWSTs 1A and 1B must have their bottom surfaces inspected in accordance with the NUREG-2191, Table XI.M29-1. Specifically, for each 10-year period starting 10 years before the SPEO, a volumetric inspection of the tank bottom is required to be performed from the inside surface of the tanks. The new tank bottom thickness inspections will use a low-frequency electromagnetic testing (LFET) technique and, as necessary, follow-up ultrasonic examinations. Any regions below nominal plate thickness (in excess of plate manufacturing tolerance) will have a follow-up ultrasonic thickness reading. If there are areas of significant loss of material that could impact the pressure boundary function, future ultrasonic thickness measurements and trending will be performed.
Water Spray Fixed Systems		
Strainers (after each system actuation)	10.2.1.6, 10.2.1.7, 10.2.7	The relevant functional test procedure and preventive maintenance activities are (or will be) performed every 18 months (based on the refueling outage interval, but not necessarily during refueling outages), which meets the interval requirements of NUREG-2191, Table XI.M27-1, Note 10. The startup transformers' deluge/spray test intervals will be changed from 3 years to 18 months for consistency with NUREG-2191 and NFPA 25. The relevant procedure and preventive maintenance activities will be enhanced to meet the inspection, flushing, and parts replacement and repair requirements of NFPA 25, Sections 10.2.1.7, 10.2.7, and associated subsections. These enhancements include flushing the mainline strainers until clear after each operation or flow test, inspecting and cleaning the strainers in accordance with the manufacturer's instructions, and replacing or repairing damaged or corroded parts. 10.2.1.6: Nozzle strainers [where applicable] shall be removed, inspected, and cleaned during the flushing procedure for the mainline strainer. 10.2.1.7: Mainline strainers shall be removed and inspected [at least] every 5 years for damaged and corroded parts. 10.2.7* Strainers. 10.2.7.1: Mainline strainers (basket or screen) shall be flushed until clear after each operation or flow test. 10.2.7.2: Individual water spray nozzle strainers [where applicable] shall be removed, cleaned, and inspected after each operation or flow test.

Description	NFPA 25 Section	Required Enhancements
		10.2.7.3: All strainers shall be inspected and cleaned in accordance with the manufacturer's instructions. 10.2.7.4: Damaged or corroded parts shall be replaced or repaired.
Operation test (refueling outage interval)	10.3.4.3	The relevant functional test procedure and preventive maintenance activities are (or will be) performed every 18 months (based on the refueling outage interval, but not necessarily during refueling outages). The relevant procedure and preventive maintenance activities test open head spray nozzles with water and meet the NFPA 25, Section 10.3.4.3.1 requirement by ensuring that spray patterns are not impeded by plugged nozzles, that nozzles are correctly positioned, and that obstructions do not prevent discharge patterns from wetting surfaces to be protected. The relevant procedure and preventive maintenance activities also meet the requirements of NFPA 25, Section 10.3.4.3.2 to retest systems after cleaning if obstructions are found. 10.3.4.3* Discharge Patterns. 10.3.4.3.1* The water discharge patterns from all of the open spray nozzles shall be observed to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. 10.3.4.3.1.1 Where the nature of the protected property is such that water cannot be discharged, the nozzles shall be inspected for proper orientation and the system tested with air to ensure that the nozzles are not obstructed. 10.3.4.3.2 Where obstructions occur, the piping and nozzles shall be cleaned and the system retested. The relevant procedure and preventive maintenance activities will be annotated to credit existing steps for the above NFPA requirements and enhanced to state that if loose deposits are identified in the piping, and the evaluation determines that the deposits must be removed, then the piping is required to be flushed repeatedly, in accordance with NFPA 25 Annex D.5, until it is determined that either no deposits are left or that the remaining deposits pose no blockage threat. Areas where excessive deposits are found will undergo more thorough volumetric wall testing to ensure minimum wall thickness is met.
Foam Water Sprinkler Systems		
Strainers	11.2.7.1	N/A
Operational Test Discharge patterns	11.3.2.6	N/A
Storage tanks	Visual inspection for internal corrosion	N/A

Description	NFPA 25 Section	Required Enhancements
Valves and System-Wide Testing		
Main drain test	13.2.5	Relevant fire water system testing/flushing procedures and preventive maintenance activities will be revised to incorporate the following instructions and requirements for the fire main drain test from NFPA 25, Section 13.2.5 and subsections. Steps with asterisks have additional clarifying information in NFPA 25, Annex A. These functional test procedures and preventive maintenance activities are or will be performed at least every 18 months (based on the refueling outage interval, but not necessarily during refueling outages), which meets the interval requirements of NUREG-2191, Table XI.M27-1, Note 10. The required steps and information are as follows: 13.2.5*: A main drain test shall be conducted [at least on a refueling outage interval (i.e., every 18 months)] at each water-based fire protection system riser to determine whether there has been a change in the condition of the water supply piping and control valves and any time the control valve is closed and reopened at system riser. 13.2.5.1: In systems where the sole water supply is through a backflow preventer and/or pressure reducing valves, the main drain test of at least one system downstream of the device shall be conducted on a quarterly basis. 13.2.5.2: When there is a 10 percent reduction in full flow pressure when compared to the original acceptance test or previously performed tests, the cause of the reduction shall be identified and corrected if necessary. Per NUREG-2191 Table XI.M27-1, the following notes also apply: Items in areas that are inaccessible because of safety considerations such as those raised by continuous process operations, radiological dose, or energized electrical equipment are inspected during each scheduled shutdown but not more often than every refueling outage interval. Calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.
Obstruction Investigation		
Obstruction, Internal Inspection of Piping	14.2, 14.3	A new procedure will be prepared and implemented to incorporate the following instructions and requirements for internal inspection of piping and obstruction investigation from NFPA 25, Sections 14.2, 14.3, and subsections. Steps with asterisks have additional clarifying information in NFPA 25, Annex A. The required steps and information are as follows: 14.2: Internal Inspection of Piping. 14.2.1: Except as discussed in 14.2.1.1 and 14.2.1.4 below, an inspection of piping and branch line conditions shall be conducted every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material. 14.2.1.1: Alternative nondestructive examination methods [that can ensure that flow blockage will not occur] shall be permitted. 14.2.1.2: Tubercules or slime, if found, shall be tested for indications of microbiologically influenced corrosion (MIC).

Description	NFPA 25 Section	Required Enhancements
		14.2.1.3*: If the presence of sufficient foreign organic or inorganic material is found to obstruct pipe or sprinklers, an obstruction investigation shall be conducted as described in Section 14.3. 14.2.1.4: Non-metallic pipe shall not be required to be inspected internally. 14.2.1.5: In dry pipe systems and pre-action systems, the sprinkler removed for inspection shall be from the most remote branch line from the source of water that is not equipped with the inspector's test valve. 14.2.1.6*: Inspection of a cross main is not required where the system does not have a means of inspection. 14.2.2*: In buildings having multiple wet pipe systems, every other system shall have an internal inspection of piping every 5 years as described in 14.2.1 above. 14.2.2.1: During the next inspection frequency required by 14.2.1 above, the alternate systems not inspected during the previous inspection shall have an internal inspection of piping as described in 14.2.1. 14.2.2.2: If the presence of foreign organic and/or inorganic material is found in any system in a building during the 5 year internal inspection of piping, all systems shall have an internal inspection. 14.3: Obstruction Investigation and Prevention. 14.3.1*: An obstruction investigation shall be conducted for system or yard main piping wherever any of the following conditions exist: (1) Defective intake for fire pumps taking suction from open bodies of water (2) The discharge of obstructive material during routine water tests (3) Foreign materials in fire pumps, in dry pipe valves, or in check valves (4)*Foreign material in water during drain tests or plugging of inspector's test connection(s) (5) Plugged sprinklers (6) Plugged piping in sprinkler systems dismantled during building alterations (7) Failure to flush yard piping or surrounding public mains following new installations or repairs (8) A record of broken public mains in the vicinity (9) Abnormally frequent false tripping of a dry pipe valve(s) (10) A system that is returned to service after an extended shutdown (greater than 1 year) (11) There is reason to believe that the sprinkler system contains sodium silicate or highly corrosive fluxes in copper systems (12) A system has been supplied with raw water via the fire department connection (13) Pinhole leaks

Description	NFPA 25 Section	Required Enhancements
		(14) A 50 percent increase in the time it takes water to travel to the inspector's test connection from the time the valve trips during a full flow trip test of a dry pipe sprinkler system when compared to the original system acceptance test. 14.3.2*: Systems shall be examined for internal obstructions where conditions exist that could cause obstructed piping. 14.3.2.1: If the condition has not been corrected or the condition is one that could result in obstruction of the piping despite any previous flushing procedures that have been performed, the system shall be examined for internal obstructions every 5 years. 14.3.2.2: Internal examination shall be performed at the following four points: (1) System valve (2) Riser (3) Cross main (4) Branch line 14.3.2.3: Alternative nondestructive examination methods [that can ensure that flow blockage will not occur] shall be permitted. 14.3.3*: If an obstruction investigation indicates the presence of sufficient material to obstruct pipe or sprinklers, a complete flushing program shall be conducted by qualified personnel. [For obstruction investigation flushing procedures, refer to NFPA 25 Annex D.5.] If loose deposits are identified in the piping, and the evaluation determines that the deposits must be removed, then the piping is required to be flushed repeatedly, in accordance with NFPA 25 Annex D.5, until it is determined that either no deposits are left or that the remaining deposits pose no blockage threat. Areas where excessive deposits are found will undergo more thorough volumetric wall testing to ensure minimum wall thickness is met. Per NUREG-2191 Table XI.M27-1, the following notes also apply: Items in areas that are inaccessible because of safety considerations such as those raised by continuous process operations, radiological dose, or energized electrical equipment are inspected during each scheduled shutdown but not more often than every refueling outage interval. Calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements. Additionally, the new procedure will specify that portions of water-based fire protection system components that have been wetted but are normally dry, such as dry-pipe or preaction sprinkler system piping and valves, are subjected to augmented testing and inspections beyond those of NUREG-2191 Table XI.M27-1. The augmented tests and inspections are conducted on piping segments that cannot be drained or piping segments that allow water to collect: In each 5-year interval, beginning 5 years prior to the SPEO, either conduct a flow test or flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100 percent of the internal surface of piping

Description	NFPA 25 Section	Required Enhancements
		segments that cannot be drained or piping segments that allow water to collect. In each 5-year interval of the SPEO, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections. Measurement points are obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, MIC). The 20 percent of piping that is inspected in each 5-year interval is in different locations than previously inspected piping. If the results of a 100-percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary.
General		
General	N/A	The relevant procedure will be revised to ensure the following actions are performed: Inspections and tests shall be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. The inspections and tests shall follow site procedures that include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes. Fast-response and traditional sprinkler heads shall either be replaced or tested in accordance with NFPA 25 prior to exceeding their 20 year or 50 year service life, respectively. If the sprinkler heads are not replaced, the required testing will be repeated at 10 year intervals. If the environmental (e.g., type of water, flowrate, temperature) and material that exist on the interior surface of the underground and buried fire protection piping are similar to the conditions that exist within the above grade fire protection piping, the results of the inspections of the above grade fire protection piping will be extrapolated to evaluate the condition of buried and underground fire protection piping for the purpose of identifying inside diameter loss of material.
General	N/A	The relevant procedure will incorporate the methodology for extending fire protection surveillance frequencies consistent with EPRI Report 1006756, NEIL Loss Control Standards, and NRC guidance as follows: The data collection guidelines in the procedure follow the NEIL guidelines for historic reliability calculations and that the number of years prior to the SPEO, from which data would be collected for modifying test and inspection frequencies, is determined based on the current surveillance intervals under evaluation. Surveillances up to quarterly require 2 years of data, surveillances performed in the range of quarterly up to annually require 3 years of data, and surveillances performed in the range of annually require up to fuel cycle require 5 years of data. The data collection guidelines include the bounding recommendations for sample size from EPRI Report 1006756. To modify test and inspection frequencies, a minimum sample size of 100 independent samples is recommended. This amount of data will ensure low uncertainty and avoid excessive failure sensitivity. A sample size of 100 is a desired lower limit,

Description	NFPA 25 Section	Required Enhancements
		but the analysis can be done with fewer points if a small number of components are involved. The use of performance data to modify surveillance intervals is based on the current length of the surveillance interval. Since CWST 1A and 1B external visual inspections are currently performed on an annual basis, the interval for these inspections can be changed (lengthened) upon successful evaluation of past inspection results and concurrence by NEIL. Performance data will not be used to modify the following surveillances, since their prescribed intervals are greater than two times the refueling interval: CWST volumetric and internal tests and inspections, underground flow tests, and inspections of normally dry but periodically wetted piping that will not drain due to the respective piping configuration.

Note: Items with asterisks have additional clarifying information in NFPA-25, Annex A.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

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 PSL 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. (Agencywide Documents Access and Management System (ADAMS) Accession Nos. 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, "Corrosion in Fire Protection Piping": It was determined that this external OE (as well as others) was not evaluated within a timely manner. As a result, an AR was issued to document the program flaw and to ensure that the OE was evaluated by another AR. The evaluation contained within the second AR stated that the existing condition and methods present at PSL were determined to provide adequate means for personnel to identify degrading condition of the fire water supply piping in pre-action and wet pipe sprinkler systems installed/in service at PSL and no further action was required. The evaluation did not evaluate the open head fixed water spray systems used by the outdoor transformers, etc. which are the systems most likely to have periodically wetted nondraining sections. The enhancements associated with Element 4 will ensure that all periodically wetted nondraining sections are identified and properly managed.

Plant Specific Operating Experience

The AMP Notebooks related to the fire protection program clarified that the sprinkler heads are either being tested or replaced prior to the respective unit reaching 50 years in age. The AMP notebooks also provide a recap of relevant health reports, procedures, work orders, etc.

The quarterly fire protection program health reports from October 2015 through October 2020 were evaluated as part of the SLRA OE review. As of January 2021, the 3rd and 4th quarters for 2020 had not been officially scored. Quarters 2 and 1 of 2020 and all of the 2019 quarters were scored "green". Most scores in 2018 and earlier were "white". Most of the latest issues do not appear to be fire water system related, but more related to fire detection and fire prevention in general.

Between 2010 and 2020, several ARs were initiated to evaluate and/or correct conditions related to the PSL fire water system.

- In September 2017, CWSTs 1A and 1B had several rust spots on the exterior of the respective tank bases. The rust and delaminated paint spots were likely triggered by the salt-laden outdoor air environment. Repairs to the external CWST 1A and 1B welds, adjacent in-scope piping corrosion and leaks are scheduled for completion in 2021 as part of the CWST Repair Capital Project.

- In August 2017, during the 1B fire pump surveillance, an elbow near the north side of CWST 1B was observed to be leaking 2-3 drops per minute at a soft-patch repair. The piping, flange, and bolting exhibited significant surface corrosion. There appeared to be corrosion on the section of pipe beneath the soft-patch. Repairs to the external CWST 1A and 1B welds, adjacent in-scope piping corrosion are scheduled for completion in 2021 as part of the CWST Repair Capital Project.

- In August 2017, during a UT examination of a 4-inch fire header in the U2 reactor auxiliary building (RAB), several corrosion cells caused by service water line leaks from above were cleaned and measured for remaining wall thickness. The remaining wall thickness at the corrosion cells was less than the 87.5 percent of the nominal wall thickness screening criteria. Remaining wall thickness was reviewed by Engineering and determined to be acceptable based upon minimum wall thickness criteria.

- In March 2017, during a License Renewal (LR) inspection of a U2 fire water system strainer, no observable material loss attributable to galvanic corrosion was evident. The SS strainer was reinserted into the cast iron housing to inspect specifically for the strainer "feet" contact area around the circumference of the housing. All six "feet" contact areas were examined with no evidence of material loss due to galvanic corrosion. However there were uniform heavy general and pitting corrosion cells inside the housing and the inlet and discharge piping. These corrosion cells were not in excess of 1/16-inch deep. Immediate repair was not required since the degradation was minor; however, A WR and WO were issued to repair the corrosion cells. The WO is scheduled to be worked in accordance with work management and System and Program Health program priorities.

- In November 2011, the fire protection piping supplying the nuclear training center (NTC) suppression system was identified as corroded. The identified corrosion was located at the floor level upstream of fire water supply isolation valve. The affected piping is located inside the air conditioning (A/C) equipment room within the south side of the NTC. The piping was repaired. Although this fire water piping is outside the scope of SLR, it was included for completeness.

- In May 2014, a question was raised by the NRC Resident Inspector regarding station awareness of the condition of the above ground fire pump piping in the CWST area. Localized corrosion cells were noted on the piping/stanchion and stanchion/baseplate interfaces, possibly due to the salt-laden outdoor air. A walkdown by engineering confirmed the presence of the localized corrosion cells on several fire protection lines. Corrosion cells were noted on 11 large bore stanchions and 2 small bore restraints. The nominal pipe wall thickness for the schedule 40 carbon steel 14-inch diameter piping is 0.438 inches. An informational piping minimum wall thickness due to hoop stress of 0.060 inches was determined using system operating pressure. Although some piping metal loss was noted at several pipe/stanchion saddle interface locations, based on experience and engineering judgment the pressure boundary of the piping was not challenged. The corrosion products were removed, the affected areas inspected and repaired, as necessary, and the supports coated and reassembled.

- In January 2016, a fire protection pipe that serves the north warehouse had failed and had a crack between 1 and 2 feet in length. A sample of the failed piping was sent to an off-site vendor for evaluation to determine if selective leaching was a factor. Mechanical stress, rather than selective leaching or aging-related degradation, was determined to be the primary cause of the pipe failure. The piping was repaired.

- In March 2017, during an LR inspection of a U2 fire protection system, coatings degradation was identified on the fire protection piping within the RAB and turbine building. The coatings condition was leading to minor and localized corrosion at the time with minor loss of material. Immediate recoating was not required since the degradation was minor; however, WRs and WOs were issued to recoat the piping. The WO is scheduled to be worked in accordance with work management and System and Program Health program priorities.

- In June 2019, externally corroded preaction system piping downstream of a diaphragm chamber supply valve and a section near the pre-action valve seal water strainer was identified. The piping was repaired.

- In September 2019, the external surface of the 1A fire pump recirculation line had become degraded and rusty. The section of pipe was approximately 3 feet in length. The piping was replaced.

- In September 2020, the CWST 1A and 1B tank internals were visually inspected and UT examinations of the tank bottoms were performed for LR. The inspection report attached to this AR stated that, in general, UT results show tank floor thickness within 10% of nominal thickness. Internal coatings failed in some locations in the tank floor, resulting in several locations of localized pitting, some of which are below the 0.225-inch minimum wall thickness for the tank floor. There were also other tank components that were corroded due to localized coatings failures. Repairs to the external CWST 1A and 1B internal tank floor pitting are scheduled for completion in 2021 as part of the CWST Repair Capital Project. Internal CWST recoating is scheduled to be implemented in 2022 as part of the same CWST Repair Capital Project.

- In October 2012, Nuclear Oversight determined that out-of-service fire protection system equipment was not being prioritized to be repaired in a timely manner, which was resulting in continual degradation of the components due to loss of material due to corrosion. Specifically, the Unit 2 heater drain pump sprinkler system was out of service. The action was assigned to work management to schedule the work. The WO was added to the Operation Focus item list to track to completion and repairs were completed.

- In June 2013, Nuclear Oversight identified that the small bore U2 turbine lubricating oil deluge system piping had rust and ongoing loss of material due to corrosion. This small bore piping and associated hardware were in need of recoating. A follow-up AR determined that the recoating was subsequently performed.

- In October 2014, the 2A startup transformer deluge sprinkler supply piping located in the U1 switchgear area was externally corroded. Due to relatively the low system pressure of this line, failure was not considered likely since most of the piping only exhibited surface rust. Due to the localized nature of the corrosion (pits) only potential failure would consist of weeping pit location. Therefore, the system would still perform as intended. A WO was issued to repair and recoat the piping. The WO is scheduled to be worked in accordance with work management and System and Program Health program priorities.

- In February 2016, the supply piping to CWSTs 1A and 1B from Municipal Utilities was found degraded. There were two existing through wall leaks with soft patches that were applied at least 5 years prior. Both patches seem to be holding but do nothing to mitigate the underlying corrosion issue inside the piping. The 1A CWST inlet line was also starting to show signs of degradation on the union connecting the underground cast iron line from the city supply to the above ground steel line. A WO to repair the piping and replace the patches was created and is scheduled to be worked in accordance with work management and System and Program Health program priorities.

- In May 2016, while Operations was attempting to restore the U2 dry storage warehouse sprinkler system, the supply line leading up to the sprinkler bell had a through wall leak. Operations stopped the system restoration and re-isolated the system. A WO repaired the piping.

- In September 2016, the U1 turbine lubricating oil (TLO) deluge system test was performed. When the deluge was actuated, there were three through wall leaks. One at the elbow for the east side upper ring of the east TLO tank, one at the elbow going to the up to the rings on the west TLO tank, and one at a union on the line going to the west TLO tank. The piping leaks were repaired in November 2016.

- In January 2019, the outdoor 1-inch pipe downstream of the orifice on the 1A fire pump recirculation line was determined to have external corrosion and paint degradation. A WO replaced the corroded piping.

- In March 2020, while performing the U2 TLO deluge system testing, a through wall leak was discovered at a threaded joint on the deluge sprinkler piping under the U2 TLO reservoir. The piping was replaced.

<u>Program Assessments and Evaluations</u>

On November 20, 2015 and October 20, 2017, the NRC completed post-approval site inspections for License Renewal for PSL Unit 1 and Unit 2, respectively, in accordance with NRC IP71003. The NRC inspectors did not identify any findings or violations of more than minor significance and determined that the overall implementation of aging management programs and time-limited aging analyses was consistent with the licensing basis of the facility. The inspectors also determined that the regulatory requirements of 10 CFR 54.37(b) were met, and commitment changes were evaluated and reported in accordance with the applicable requirements. With respect to fire protection, the NRC inspectors verified that PSL was aligned with its commitments to test or replace sprinklers before the respective Units reach 50 years of operation. No gaps related to the fire protection program were identified.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021. No findings related to the PSL Fire Water System AMP were identified.

The PSL 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 PSL Fire Water System 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.2.3.17 Outdoor and Large Atmospheric Metallic Storage Tanks

Program Description

The PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP is an existing AMP previously part of the Periodic Surveillance and Preventive Maintenance (PSPM) Program and Structures Monitoring Program, that consolidates and coordinates existing activities for subject tanks that are associated with the following AMPs:

- PSL Structures Monitoring (Section B.2.3.33) AMP
- PSL External Surfaces Monitoring of Mechanical Components (Section B.2.3.23) AMP
- PSL Water Chemistry (Section B.2.3.2) AMP
- PSL Fuel Oil Chemistry (Section B.2.3.18) AMP
- PSL One-Time Inspection (Section B.2.3.20) AMP
- PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.3.28) AMP

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:

- Unit 1 Refueling Water Tank (U1 RWT)
- Unit 2 Refueling Water Tank (U2 RWT)
- Unit 2 Primary Water Storage Tank (U2 PWST)
- Treated Water Storage Tank (TWST)
- Unit 1 Condensate Storage Tank (U1 CST)
- Unit 2 Condensate Storage Tank (U2 CST)
- Diesel Oil Storage Tank 1A (DOST 1A)
- Diesel Oil Storage Tank 1B (DOST 1B)

This AMP manages loss of material and cracking by conducting one-time and 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 (except the U1 RWT, see exception discussion below) are conducted to detect degradation and ensure corrosion from the inaccessible undersides will not cause a loss of intended tank function. Caulking/sealant is applied to the U1 RWT, U2 RWT, U2 PWST, TWST, U1 CST, U2 CST, DOST 1A, and DOST 1B as a preventive measure.

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. The carbon steel, aluminum, and SS tanks will have external visual inspections performed every 18 months. The volumetric tank bottom thickness measurements will be performed for the U2 RWT, U2 PWST, TWST, DOST 1A, DOST 1B, and the CSTs at intervals no greater than 10 years. Additionally, for the CSTs, DOSTs, TWST, and U2 PWST, the coatings inspections of the interior, including the above the U2 PWST internal floating roof, will be performed by the PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.3.28) AMP.

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 OE 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 requires the measured or projected tank bottom thickness to be greater than 87.5 percent of the nominal plate thickness. The U1 RWT tank bottom epoxy lining acceptance criteria are defined in the SL1-20 engineering evaluation as follows:

- Hardness - The liner shall be considered acceptable if there are no instances in which the knife test produces a cut in the surface.
- Delamination and Adhesion - The liner shall be considered acceptable for delamination if there are no areas for which the sounding examination indicates delamination. The liner shall be considered acceptable for adhesion if there are no areas of adhesion failure with a greatest dimension of 5 feet or greater (as long as all other properties in the failure area meet the acceptance criteria).
- Peeling and Flaking - The liner shall be considered acceptable if there are no areas of peeling or flaking observed.
- Undercutting - The liner shall be considered acceptable if there are no instances of undercutting observed by visual examination. In addition, in the examination of the edge of the liner on the vertical surfaces, there shall be no instances where the knife point can be pushed more than 1/8-inch under the edge of the liner.
- Blistering - The liner shall be considered acceptable if there are no areas of blistering observed. Minor blistering may be considered acceptable if the following conditions are met:
    - The size of blistering does not exceed Blister Size No. 6 (as described in ASTM D714);
    - The frequency of blistering is "few" or less (as described in ASTM D714);
    - The depth of any blister does not extend beyond the bottom of the topcoat.
- Cracking - The liner shall be considered acceptable if there are no areas of cracking observed.

- Checking - The liner shall be considered acceptable if there are no areas of checking observed, or if any checking present does not extend more than 1/32-inch from the top of the liner.
- Discoloration - The liner shall be considered acceptable if there are no areas of gross discoloration observed (this condition will be subject to the evaluation of the Nuclear Coatings Specialist or designee).
- Holidays - The liner shall be considered acceptable if there are no holidays observed.
- Pinholes - The liner shall be considered acceptable if there are no pinholes observed which penetrate to the substrate.

When the acceptance criteria are not met, then an evaluation or corrective action is initiated to provide reasonable assurance 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 bottom interface inspection are to confirm there are no signs of degradation (minimal corrosion) or water intrusion. Any degradation of paints, coatings, or the U2 PWST internal floating roof or evidence of corrosion is reported and further evaluation is required to determine if repair or replacement should be conducted. Any conditions are documented, evaluated, and repaired as necessary.

More frequent inspections may need to be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). The need for more frequent inspections will be determined in accordance with the PSL corrective action program and NUREG-2191, Section XI.M29.

NUREG-2191 Consistency

The PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP, with enhancements, will be consistent with exception to the 10 elements of NUREG-2191, Section XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”.

Exceptions to NUREG-2191

The PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP will take the following exception to the NUREG-2191 guidance:

The PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP will take an exception to performing volumetric examinations of the U1 RWT floor, since it is not feasible. The aluminum floor for the U1 RWT has through-wall holes and this metal floor was not credited for the original License Renewal. Instead the floor is lined with a fiberglass-reinforced vinyl ester epoxy material (Dudick Protecto-Line 800), which is credited for performing the pressure boundary function for SLR. Instead of volumetric examinations, visual inspections will be used to inspect for cracking and loss of material as prescribed in an approved NRC relief request documented in FPL engineering evaluations and preventive maintenance activities. The preventive maintenance activities include diver inspections performed at a refueling outage interval and a drained tank inspection performed at an interval of every 6th refueling outage. The drained tank inspection will continue to inspect for galvanic corrosion cells between the SS piping, and manway flanges and the aluminum tank.

Enhancements

The PSL Outdoor and Large Atmospheric Metallic Storage Tanks 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

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 PMs, to:
	• Address the interfaces, handoffs, and overlaps between the PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP and the following AMPs:
	  ○ PSL Structures Monitoring (Section B.2.3.33) AMP;
	  ○ PSL External Surfaces Monitoring of Mechanical Components (Section B.2.3.23) AMP;
	  ○ PSL Water Chemistry (Section B.2.3.2) AMP;
	  ○ PSL Fuel Oil Chemistry (Section B.2.3.18) AMP;
	  ○ PSL One-Time Inspection (Section B.2.3.20) AMP;
	  ○ PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.3.28) AMP and;
	  ○ PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B.2.3.1) AMP.
	• Direct periodic (18-month interval) visual inspection of tank-to-concrete caulking/sealants, with mechanical manipulation as appropriate. Update or reactivate existing caulking/sealant inspection PMs and create new caulking/sealant inspection PMs as needed. These caulking/sealant inspections are performed by the PSL Structures Monitoring (Section B.2.3.33) AMP.
	• Direct 10-year bottom thickness measurement of the U2 RWT, U2 PWST, TWST, DOST 1A, DOST 1B, and the CSTs, using low-frequency electromagnetic testing (LFET) techniques with follow-on UT examination, as necessary, at discrete tank locations identified by LFET.
	• Direct baseline one-time interior visual inspections of the RWTs. Direct 10-year surface examination inspections of the aluminum and SS RWTs' interior nonwetted surface and exterior surface for evidence of loss of material and cracking. The surface examinations will inspect 25 1-square-foot sections or 25 1-linear-foot sections of welds. If evidence of cracking is identified, then a surface examination is also performed to determine the extent of the cracking.

Element Affected	Enhancement

	• Clarify that subsequent inspections are conducted in different locations unless this AMP includes a documented basis for conducting repeated volumetric and surface 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 inspections and tests within the scope of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) follow procedures consistent with the ASME Code, including ASME Code Section XI. 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, or in the case of one-time inspections, identified degradation is projected to the end of the SPEO.
	• Clarify that results are evaluated against acceptance criteria to confirm or adjust timing of subsequent inspections, or in the case of one-time inspections, schedule follow-up inspections.
	• State the acceptance criteria as follows:
	  o No degradation of paints or coatings (e.g., cracking, flakes, or peeling), or the U2 PWST internal floating roof;
	  o No non-pliable, cracked, or missing caulking/sealant for the tank bottom interface;
	  o No indications of cracking of a SS tank (U2 RWT). No indications of cracking of the aluminum walls and ceiling of the U1 RWT, and;
	  o Measured or projected tank bottom thickness must be greater than 87.5 percent of the nominal plate thickness. (Not applicable to the U1 RWT)
	• 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:
	  o Report degradation via a condition report (CR) then perform an engineering evaluation or repair/replace the degraded component as needed.
	  o Repair or replace the degraded component as determined by engineering evaluation and perform follow-up examinations. For one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.

Element Affected	Enhancement
	o Expand the inspection to include all tanks of with the same material-environment combination (for DOST degradation). o For other sampling-based inspections (e.g., 20%, 25 locations) the smaller of five additional inspections or 20% of the inspection population is conducted. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause is conducted to determine the further extent of inspection. The additional inspections include inspections at all of the Units with the same material, environment, and aging effect combination. Sample expansion inspections that happen in the next inspection interval are part of the preceding interval.
4. Detection of Aging Effects	Perform baseline one-time interior visual inspections of the RWTs. Perform 10-year surface examination inspections of the aluminum and SS RWTs' interior nonwetted surface and exterior surface for evidence of loss of material and cracking. The surface examinations will inspect 25 1-square-foot sections or 25 1-linear-foot sections of welds. If evidence of cracking is identified, then a surface examination is also performed to determine the extent of the cracking.
4. Detection of Aging Effects	Perform 10-year LFET tank bottom thickness examinations of the U2 RWT, U2 PWST, TWST, DOST 1A, DOST 1B, and the CSTs, with follow-on UT at discrete locations.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions. 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 OE provided clear examples aging effects to check for with respect to the site-specific OE review. With respect to these issues, PSL has experienced some coating/paint delamination and some rusting/corrosion on the subject tanks, but none that threatened the function of the tanks. The following industry OE was identified as relevant to the PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP:

- IN 2013-18: In response to the refueling water storage tank degradation and leakage issues other nuclear plants, PSL evaluated how it manages aging of the RWTs. The evaluation determined that at the time no similar degradation issues (leaks at tank floor welds, tank floor nozzle welds and tank to tank wall welds and denting at aluminum nozzles encased in concrete) were occurring at the PSL RWTs.

Plant Specific Operating Experience

There are no quarterly program health reports specific to the in-scope tanks, although there are health reports for relevant systems. The respective health reports from January 2015 through October 2020 for the following systems were reviewed: containment spray and injection, condensate, chemical and volume control, and EDG fuel oil; the only aging issue relevant to the in-scope tanks was an AR related to the U1 CST coating degradation. The health reports for the Structures Monitoring (Section B.2.3.33) AMP were also reviewed, and these health reports identified coating cracks in the U1 DOST area and cracks in the miter joints of the respective flood wall, as well as rusted hold-down bolts at the bottom of the U1 CST.

A recent OE search was performed for SLR which covered a date range of October 1, 2010 through October 1, 2020. This search was supplemented using the NextEra NAMS system to identify ARs (ARs) linked to the in-scope tanks (U1 RWT, U2 RWT, U2 PWST, TWST, U1 CST, U2 CST, DOST 1A, and DOST 1B), which also included ARs outside of the date range. This search identified several ARs related to the in-scope tanks, such as:

RWTs (U1 and U2):

- In February 2020, a diving inspection that included UT testing was performed on the U2 RWT. The inspection consisted of 20 UT straight beam readings on the RWT floor. The wall thickness readings had an average thickness of 0.273 inches, which was close to the nominal thickness of 0.250 inches and above the acceptance criteria of 0.225 inches. There were no relevant indications identified by the diver performing the UT inspection.

- In April 2011, the U1 RWT caulking inspection had not been performed on time. An extent of condition was performed and revealed that a weekly report on project preventive maintenance activities had not been performed. In response to the AR, this responsibility was clarified and assigned. The caulking inspection performed in May 2011 revealed cracks on the caulking. A work order replaced the cracked caulking with new caulking, as needed, and as an additional measure Belzona was applied to the caulked seal.

- In March 2018, during a U1 RWT internal floor lining remote inspection, three areas with 6-inch stress cracks were discovered on the fiberglass-reinforced vinyl ester epoxy lining material (Dudick Protecto-Line 800) adjacent to a previous repair. The cracking appeared to be in the top coat and did not create a leak path due to the two remaining layers of the coating. There was no evidence of any peeling, flaking, undercutting, or blistering. An evaluation was performed as part of the AR and as a corrective measure, a follow up inspection was scheduled for the next outage. Repairs were performed under a work order.

- In December 2020, minor coating peeling was discovered during the annual inspection of the Unit 1 RWT caulking of the tank/ring foundation joint. The caulking was installed as a coating over the joint overlapping the tank and the concrete to form an impermeable barrier. The minor peeling was occurring in the area overlapping the concrete. There was sufficient distance between the peeling and the joint to prevent water from reaching the tank surface. The function of the caulking was not adversely impacted. A work order was created to perform the repair and is scheduled for August 2021.

- In May 2009, an internal inspection of the U2 RWT was completed. No issues were identified and photographs documented the inspection results.

- In June 2012, the hold-down bolts supporting the U2 RWT were rusting and required a coatings application. The “chair” type bolts used were known to collect water inside the support box. The bolt attachment needed a special coatings application, such as a densyl tape and/or foam. The affected bolts were only a few of the thirty bolts supporting the tank. A work order performed the cleaning and coating repair.

- In April 2015, an inspection of the U1 RWT drain connection outlet flange was performed. That inspection revealed minor pitting on the flange gasket seating surface and additional pitting in the vicinity of the flange bolt hole circle. A work order that installed an adjacent valve cleaned and coated the gasket seating surface.

PWST (U2):

- In August 2011, the U2 PWST interior was inspected. No degradation issues were identified within the normally wetted interior of U2 PWST, however, the inspection of the non-wetted area between the floating roof seal and the tank top identified several minor areas (approximately eight) of corrosion within previous Belzona-repaired areas. These areas were approximately ½-inch in diameter and in all cases the carbon steel substrate was corroding. The minor corrosion identified did not affect the ability of the tank to perform its design function; therefore, no corrective action was required. A follow-up tank inspection is scheduled for the refueling outage in Spring 2023.

TWST:

- In September 2020, a diving inspection that included UT testing was performed on the TWST. No issues were identified from the UT examination.

- In June 2017, a worker noted that the TWST was showing corrosion at the bottom flange. A leak developing at this area would be a challenge to repair. Work orders removed the flange corrosion and recoated the flange.

- In August 2019, a pre-job walkdown was performed to identify areas of noted corrosion cells on the TWST that may challenge minimum wall thickness, and these areas would then be UT evaluated prior to surface preparation evolutions. A work order performed the UT thickness examination and cleaned and recoated the corroded wall areas.

- In August 2019, when prepping external corrosion cells, painters identified water leakage. An NDE examination was performed and a work order repaired the degraded areas.

CSTs (U1 and U2):

- In February 2020, a diving inspection that included UT testing was performed on the U2 CST. The inspection consisted of 20 UT straight beam readings on the CST floor. The wall thickness readings had an average thickness of 0.253 inches, which was close to the nominal thickness of 0.250 inches and above the acceptance criteria of 0.225 inches. There were no relevant indications identified by the diver performing the UT inspection.

- In January 2012, during the performance of a preventive maintenance activity, I&C discovered that the flange face on the U1 CST (tank side flange) was damaged. The tank-side flange face appeared to be eroded/corroded and would possibly not reseal to maintain N2 blanket pressure on the U1 CST. A work request and work order resurfaced and recoated the damaged flange surface.

- In December 2014, an inspection identified minor corrosion and coatings degradation on the U1 CST, primarily near a bottom support plate and the level detector flange/bolting at the top of the tank. A work request and work order performed the coating repairs.

- In January 2015, a License Renewal system walkdown was performed and identified a deformed portion of the U1 CST dome. The AR evaluated the material condition and determined that the dome was structurally sound and no corrective actions were required.

DOSTs (1A and 1B):

- In February 2010, during a walkdown inspection of the DOSTs 1A and 1B, areas of degradation/corrosion were identified on the top of the tanks. No through-wall leaks were detected. A UT thickness examination was performed with the results documented in the AR. In July 2010, the degradation was further evaluated. Work orders removed the surface corrosion and recoated the DOSTs.

- In December 2015, a worker identified minor surface corrosion at DOSTs 1A and 1B and the upstream of valves' bolted joints that required surface preparation and recoating. A work request and work order performed the activities.

- In April 2020, while performing a License Renewal visual inspection walkdown of the emergency diesel generator (EDG) system, minor surface corrosion with no pitting was observed on DOSTs 1A and 1B. Work requests and work orders were issued to remove the surface corrosion and re-finish the carbon steel surfaces. The work orders are respectively scheduled for June and July of 2021.

- In October 2012, during a Fukushima-related seismic walkdown of DOST 1B, two nuts were identified as degraded. The amount of degradation did not appear to significantly impact the structural integrity of the anchors. A work request and work order changed out the existing degraded nuts with new nuts and coated.

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.

Program Assessments and Evaluations

On November 20, 2015 and October 20, 2017, the NRC completed Post-Approval Site Inspections for License Renewal for PSL Unit 1 and Unit 2, respectively, in accordance with NRC IP71003. With respect to the PSPM Program and Systems and Structures Monitoring Program, the NRC inspectors did not identify any findings or violations related to the aging management of the in-scope tanks. The inspectors determined that the regulatory requirements of 10 CFR 54.37(b) were met, and commitment changes were evaluated and reported in accordance with the applicable requirements. No findings related to the aging management of the in-scope tanks were identified.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP were identified.

The PSL 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 PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP, with enhancements and an exception, 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.2.3.18 Fuel Oil Chemistry

Program Description

The PSL Fuel Oil Chemistry AMP is an existing AMP, previously known as the Chemistry Control Program – Fuel Oil Chemistry Subprogram, 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 emergency diesel generator day tanks, which will only be drained and inspected to the extent practical. Visual inspection of accessible locations of the day tank internals will be performed, and volumetric (UT) inspection of accessible portions of the day tank as close to the bottom as possible will be performed

The PSL 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 PSL 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 PSL One-Time Inspection (Section B.2.3.20) AMP, and the PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.3.28) AMP are also used to verify the effectiveness and supplement this AMP.

Components within the scope of the PSL 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:

- DG DO DAY TK 1A1, Diesel Generator Diesel Oil Day Tank 1A1
- DG DO DAY TK 1A2, Diesel Generator Diesel Oil Day Tank 1A2
- DG DO DAY TK 1B1, Diesel Generator Diesel Oil Day Tank 1B1
- DG DO DAY TK 1B2, Diesel Generator Diesel Oil Day Tank 1B2
- DOST 1A, Diesel Oil Storage Tank 1A
- DOST 1B, Diesel Oil Storage Tank 1B
- DG DO DAY TK 2A1, Diesel Generator Diesel Oil Day Tank 2A1
- DG DO DAY TK 2A2, Diesel Generator Diesel Oil Day Tank 2A2

- DG DO DAY TK 2B1, Diesel Generator Diesel Oil Day Tank 2B1
- DG DO DAY TK 2B2, Diesel Generator Diesel Oil Day Tank 2B2
- DOST 2A, Diesel Oil Storage Tank 2A
- DOST 2B, Diesel Oil Storage Tank 2B

NUREG-2191 Consistency

The PSL Fuel Oil Chemistry AMP, with enhancements, will be consistent with exceptions to the 10 elements of NUREG-2191, Section XI.M30, “Fuel Oil Chemistry.”

Exceptions to NUREG-2191

The PSL Fuel Oil Chemistry AMP includes the following exceptions to the NUREG-2191 guidance:

1. The size and the design of the day tanks make it difficult to perform the required draining, cleaning, internal inspections, or volumetric inspection of the bottom thickness of the day tanks. Accordingly, PSL will take an exception to the cleaning and inspection requirements specified in Element 4 of the NUREG-2191, XI.M30. As an alternate to the GALL-SLR Element 4 requirements, PSL will drain and clean the day tanks to the extent practical. Visual inspection of accessible locations of the day tank internals will be performed, and volumetric (UT) inspection of accessible portions of the day tank as close to the bottom as possible will be performed.
2. Multilevel sampling or sampling from the lowest point is not used specified in Element 4 of the NUREG-2191, XI.M30. As an alternate to the GALL-SLR Element 4 requirements, the DOSTs are placed on recirculation for 30-minutes prior to sampling. The periodic recirculation of fuel oil also achieves filtering, reducing need for fuel treatments and additives by preventing contaminant build-up.

Enhancements

The PSL Fuel Oil Chemistry 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
3. Parameters Monitored or Inspected	Enhance procedures to address the analysis of stored fuels in the day tanks describing analytical techniques and test frequencies for determining water and sediment content, total particulate concentration, and microbiological contamination levels.
3. Parameters Monitored or Inspected	Enhance procedures to address periodic tank cleaning, and visual or alternative internal inspections of the day tanks.
3. Parameters Monitored or Inspected; and 4. Detection of Aging Effects	Update procedures and/or PMRQs to drain, clean and visually inspect the DOSTs at least once during the 10-year period prior to the SPEO, then periodically on a 10-year frequency during the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected; and 4. Detection of Aging Effects	Require any pressure retaining boundary degradation identified during visual inspection be supplemented with volumetric (UT) wall thickness testing including bottom thickness measurements for the DOSTs if warranted.
4. Detection of Aging Effects	Prior to the subsequent period of extended operation, a one-time inspection of selected components exposed to diesel fuel oil to be performed in accordance with the PSL One-Time Inspection (Section B.2.3.20) AMP to verify the effectiveness of the PSL Fuel Oil Chemistry AMP.
5. Monitoring and Trending	Update procedures/PMRQs to: ○ Perform periodic fuel oil sampling of the day tanks. ○ Clarify that the sampling specifically monitors the following parameters for trending purposes: water content, sediment content, biological activity, and total particulate concentration for all DOSTs and day tanks. ○ Update frequency of ASTM D975 (Reference 1.6.41) analysis to quarterly.
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	Provide acceptance criteria, consistent with industry standards, for the testing requirement and approach used to detect the presence of water, particulates, and microbiological activity in stored diesel fuel within all DOSTs and day tanks.
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 (including all DOSTs and day tanks) internal surfaces is reported and is evaluated using the corrective action program. ○ Thickness measurements of the DOST tank bottom are evaluated against the design thickness and corrosion allowance.
7. Corrective Actions	Provide corrective actions, such as addition of a biocide, to be taken should testing detect the presence of microbiological activity in stored diesel fuel.
7. Corrective Actions	Update procedures to perform corrective actions to prevent recurrence when the specified limits for fuel oil standards are exceeded during periodic surveillance.

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 PSL Fuel Oil Chemistry AMP has been effective in preventing unacceptable degradation of the in-scope systems containing fuel oil. Review for recent industry OE did not identify any significant experience related to the PSL Fuel Oil Chemistry AMP.

Plant Specific Operating Experience

The fuel oil system is routinely reviewed for water content, and no adverse conditions that would be indicative of water content in the fuel oil system have been identified. The fuel oil system piping is routed from the DOSTs to the EDGs via guard pipes, so the process fluid piping in the guard pipes is not directly in contact with concrete or the ground. The fuel oil tanks and piping are routinely inspected and have not had any significant findings or degradations in recent history.

A recent OE search was performed for SLR which covered a date range of October 1, 2010 through October 1, 2020. This search identified the following ARs related to the fuel oil chemistry program.

In April 2014, the PSL Chemistry personnel responsible for gathering samples only sampled one of the two tank trucks delivered. Even though this was a human error and the procedure was clear, PSL issued corrective action to enhance and clarify a PSL procedure to prevent reoccurrence.

In May 2015, Unit 2 DOSTs were not cleaned with a cleaning agent, which is required by the Technical Specifications. This resulted in missed surveillance test for the Unit 2 EDG. To prevent reoccurrence, a procedural enhancement was made to include instructional steps to ensure cleaning and inspection of the DOSTs are in accordance with the requirements of the applicable Technical Specifications. Additionally, work orders to clean and inspect the DOSTs were revised to incorporate these requirements.

In 2020, three ARs were issued to address new fuel oil being on the threshold of acceptance criteria. The new fuel oil was considered acceptable, especially when the new fuel is added to the existing diesel fuel oil where there was reasonable assurance that the acceptance criteria would be well within the limit values.

In May 2020, upward trend was identified in API gravity for the received diesel fuel oil tanker. In June 2020, PSL Chemistry identified issues with a delivery of diesel fuel oil prior to acceptance due to several discrepancies noted in the delivery including the API gravity analysis being outside of range limit. PSL further investigated the diesel fuel oil supplier and identified fuel in a tank that was dedicated for supplying

PSL did not meet required specifications. PSL required the supplier to resolve the quality issues to meet the contractual requirements before allowing further deliveries.

There is no separate program health report for the PSL Fuel Oil Chemistry AMP. However, the PSL Chemistry Program as a whole is tracked and trended via quarterly program health reports. The quarterly program health reports for 2015 through 2020 did not identify any conditions in the PSL Fuel Oil Chemistry AMP.

Program Assessments and Evaluations

In November 2010, a self-assessment was performed to identify areas that were not completed for PSL LR commitments. For the PSL Fuel Oil Chemistry AMP no deviations were identified.

In 2015, a focused self-assessment was performed to assess readiness for the License Renewal Implementation IP71003 Phase II inspection. There were no issues/gaps identified regarding the PSL Fuel Oil Chemistry AMP.

In 2015, the NRC completed a post-approval site inspection for License Renewal for Unit 1 in accordance with NRC IP71003. Based on the inspection samples selected for review, no findings were identified regarding the PSL Fuel Oil Chemistry AMP. The inspectors determined that PSL fully established the required AMPs, and time-limited aging analyses to manage the aging effects of in-scope SSCs through the PEO of Unit 1.

In October 2017, the NRC completed a Post-Approval Site Inspection for License Renewal for Unit 2 in accordance with NRC IP71003. The NRC inspectors did not identify any findings regarding the PSL Fuel Oil Chemistry AMP and determined that aging management activities were consistent with licensing basis documents and program procedures.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Fuel Oil Chemistry AMP were identified. However, an enhancement was made for additional personnel to become qualified to the plant's Aging Management Program Owner Mentor Guide.

The PSL 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 PSL Fuel Oil Chemistry AMP, with enhancements and exceptions, 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.2.3.19 Reactor Vessel Material Surveillance

Program Description

The PSL Reactor Vessel Material Surveillance AMP is an existing AMP, formerly a portion of the PSL 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 PSL 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 the UFSAR. Surveillance capsules are designed and located to permit insertion of replacement capsules.

This AMP includes withdrawal and testing of the surveillance capsules located at 83° for Unit 1 and 277° for Unit 2. These capsules 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 Upper Shelf Energy (USE), Pressurized Thermal Shock (PTS), and P-T limits.

The objective of the PSL Reactor Vessel Material Surveillance AMP is to provide sufficient material data and dosimetry to (a) monitor irradiation embrittlement (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 PSL Neutron Fluence Monitoring (Section B.2.2.2) AMP. The PSL 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, per the NRC-approved schedule in Unit 1 UFSAR Table 5.4-3 and Unit 2 UFSAR Table 5.3-9. 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 PSL Reactor Vessel Material Surveillance AMP is a condition monitoring AMP that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in the 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 PSL Reactor Vessel Material Surveillance AMP is also used in conjunction with the proposed PSL Neutron Fluence Monitoring (Section B.2.2.2) AMP.

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 PSL Reactor Vessel Material Surveillance AMP is consistent with exception to the 10 elements of NUREG-2191, Section XI.M31, “Reactor Vessel Material Surveillance.”

Exceptions to NUREG-2191

Unit 1 has one remaining standby capsule located at 277°. However, the capsule at 277° was found to be missing its threaded top during a 1996 vessel inspection. Without the top, this capsule cannot be removed. Unit 2 has two remaining standby capsules located at 104° and 284°. However, the remaining standby capsules have a lead factor of less than 1.0 (0.98) and will therefore not reach 72 EFPY prior to the end of the SPEO.

The PSL Reactor Vessel Material Surveillance AMP includes the following exception to the NUREG-2191 guidance, elements 3 and 5:

In order to achieve the peak 72 EFPY end-of-life fluence values used in the TLAAs for USE, PTS, ART, and P-T limits, incremental adjustments to the approved capsule withdrawal schedules for the 263° and 83° capsules in Unit 1 and the 277° capsule in Unit 2 is requested.

The PSL Unit 1 capsules at 263° and 83° have yet to be withdrawn. The capsule at 263° is requested to be adjusted from 38 EFPY to 46 EFPY to coincide with PSL's expected fluence for the 60-year license renewal period. The capsule at 83° is requested to be adjusted to 62 EFPY to coincide with the 72 EFPY projected bounding fluence. The Unit 1 vessel is weld limited, and PSL already has material data (from Beaver Valley) at >72 EFPY fluence for this limiting weld material, so the PSL capsule will provide additional data related to fluence and plate data.

The PSL Unit 2 remaining standby capsules have a lead factor of less than 1.0 and there are no plans to withdraw these capsules. The current approved withdrawal of the 277° capsule is scheduled at a fluence of 4.5 x 10^{19} n/cm^2, for the 60-year license renewal period (Unit 2 FSAR, Table 5.3-9).

Using the 72 EFPY bounding fluence projections, the Unit 1 capsule located at 83° and the Unit 2 capsule located at 277° can achieve a fluence of at least 6.38 x 10^{19} n/cm^2 and 6.56 x 10^{19} n/cm^2, respectively. These incremental changes to the Unit 1 capsule located at 83° and the Unit 2 capsule located at 277° withdrawal schedules will allow sufficient material data and dosimetry to be obtained to monitor irradiation embrittlement through the end of the SPEO.

In accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3, approval is requested to extend the withdrawal schedule for PSL Unit 1 capsule at 263° to the first refueling outage that meets or exceeds (≥) 46 EFPY with a projected fluence of 4.60 x 10^{19} n/cm^2 to bound the 60-year projected end of the PEO fluence for the Unit 1 reactor vessel. Approval is also requested to extend the withdrawal schedules for Unit 1 capsule at 83° and Unit 2 capsule at 277° to the first refueling outages that meet or exceed (≥) 72 EFPY with a projected fluence of 6.38 x 10^{19} n/cm^2 and 6.56 x 10^{19} n/cm^2, respectively, to bound the 80 year (72 EFPY) projected end of the SPEO fluence. The proposed changes to the current surveillance capsule withdrawal schedules are provided in Appendix A1 (changes for PSL Unit 1 UFSAR Table 5.4-3) and Appendix A2 (changes for PSL Unit 2 UFSAR Table 5.3-9) with revisions indicated by text deletion (strikethrough) and text addition (bold and underlined).

Enhancements

None.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions. Industry OE related to the Reactor Vessel Surveillance Program includes GL 92-01, Revision 1, “Reactor Vessel Structural Integrity,” and Supplement 1 to GL 92-01, Revision 1, “Reactor Vessel Structural Integrity.” PSL’s response to these documents has been incorporated into the Reactor Vessel Surveillance Program.

There was recent OE relative to Westinghouse capsules that were relocated and not properly seated in the new irradiation location at a TVA plant (NRC IN 2016-02), however this OE is not applicable to the CE design capsules, which are not relocatable.

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 Reactor Vessel Surveillance Program.

Plant Specific Operating Experience

In 2018, a Level 1 assessment was performed to ensure the roles and responsibilities for implementing the Reactor Vessel Integrity Program are clearly understood and accurately reflected in program procedures. Four findings were identified as summarized below:

- Station Engineering Manager vs. Fuel Director responsibilities required updates.
- Consistent documentation for cumulative EFPY determination was required.
- Training references in the fleet and site procedures required updates.
- Updates identified in fleet and site procedures for review due to nomenclature and written requirements.

All actions to address these findings have been taken.

Program Assessments and Evaluations

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in January 2021, and no findings related to the PSL Reactor Vessel Material Surveillance AMP were identified.

The PSL 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 PSL Reactor Vessel Material Surveillance AMP with exceptions 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 PSL One-Time Inspection AMP is a new AMP 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 PSL One-Time Inspection AMP will manage the aging effects of loss of material due to crevice corrosion, general corrosion, microbiologically-induced corrosion (MIC), and pitting corrosion, cracking due to stress corrosion cracking (SCC) and cyclic loading, and loss of heat transfer capability due to fouling.

The elements of the PSL 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 non-destructive examination (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. Identification of inspection locations is based on the potential for the aging effect to occur. Examination techniques are established NDE methods with a demonstrated history of effectiveness in detecting the aging effect of concern, including visual, ultrasonic, and surface techniques. Acceptance criteria is based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. The need for follow-up examinations are evaluated based on inspection results if age-related degradation is found that could jeopardize an intended function before the end of the SPEO.

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 PSL One-Time Inspection AMP is used to verify the effectiveness of the PSL Water Chemistry (Section B.2.3.2), Fuel Oil Chemistry (Section B.2.3.18), and Lubricating Oil Analysis (Section B.2.3.25) AMPs. For steel components exposed to water environments that do not include corrosion inhibitors as a preventive action or steel components that do not have wall thickness measurement examinations conducted of a representative sample of each environment between the 50th and 60th year of operation, the PSL One-Time Inspection AMP will be 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), and structural integrity]. For components susceptible to long-term loss of material due to general corrosion, wall thickness will be measured with a volumetric (UT) technique.

The PSL One-Time Inspection AMP will address potentially long incubation periods for certain aging effects and will provide a means of verifying that an aging effect is either not occurring or progressing so slowly as to have a negligible effect on the intended function of the structure or component. Situations in which additional confirmation is appropriate include: (a) an aging effect is not expected to occur, but the data are insufficient to rule it out with reasonable confidence; or (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than generally expected. For these cases, confirmation demonstrates that either the aging effect is not occurring or that the aging effect is occurring very slowly and does not affect the component or structure intended function during the SPEO based on prior OE data.

The components to be inspected shall be chosen from the various systems within the scope of the PSL Water Chemistry (Section B.2.3.2) AMP, the PSL Fuel Oil Chemistry AMP, and the PSL Lubricating Oil Analysis (Section B.2.3.25) AMP. From these lists of components, a sample of the population will be selected for inspection as part of the PSL One-Time Inspection AMP. The inspections will be scheduled as close to the end of the current operating license as practical with margin provided to ensure completion prior to commencing the SPEO. Any corrective actions will be implemented through the Corrective Action Program. The AMP may include a review of routine maintenance, repair, or inspection records to confirm that selected components have been inspected for aging degradation within the recommended time period for the inspections related to the SPEO, and that significant aging degradation has not occurred.

The PSL One-Time Inspection AMP does not address loss of material due to selective leaching. Loss of material due to selective leaching is addressed in the PSL Selective Leaching (Section B.2.3.21) AMP. The PSL One-Time Inspection AMP also does not address Class 1 piping less than 4 inches nominal pipe size since that piping is addressed in the PSL ASME Code Class 1 Small-Bore Piping AMP. Additionally, the PSL One-Time Inspection AMP will not be 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. In these cases, periodic plant specific inspections will be performed.

NUREG-2191 Consistency

The PSL One-Time Inspection AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M32, “One-Time Inspection”.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

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 OE 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 include (a) ensuring that the PSL One-Time Inspection AMP is not used for managing aging of systems or components with known age-related degradation issues, and (b) 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 (based on evaluation per EPRI 3002002850) and any circumferential transition cone welds (if replacement activities resulted in a circumferential field weld).

- The PSL steam generator divider plates are constructed of materials not susceptible to primary water stress corrosion cracking. Therefore, the PSL Unit 1 and Unit 2 steam generator divider plates do not require inspection per the PSL One-Time Inspection AMP.

- The replacement steam generators at PSL were installed as intact Units and were not cut and reassembled on location, therefore, no field welds require inspection in accordance with the PSL One-Time Inspection AMP.

Plant Specific Operating Experience

Although some one-time inspections were performed for original license renewal, these inspections were focused on systems susceptible to loss of material due to galvanic corrosion. Since the PSL One-Time Inspection AMP will not be credited for managing loss of material due to galvanic corrosion during the SPEO, these inspections are not relevant for this AMP. Likewise, some systems/components, such as the closed cooling water system components, have had opportunistic inspections performed during the PEO, but these also were not in the scope of the PSL One-Time Inspection AMP. Since there were no applicable sample groups for original license renewal, no applicable ARs are identified. ARs related to the effectiveness of the PSL Water Chemistry (Section B.2.3.2) AMP, the PSL Fuel Oil Chemistry (Section B.2.3.18) AMP, and the PSL Lubricating Oil Analysis (Section B.2.3.25) AMP are currently stated in those respective AMPs. As one-time inspections are performed prior to the SPEO, age-related degradation identified by those inspections will be documented in the PSL One-Time Inspection AMP.

The site-specific OE relevant to the PSL Water Chemistry (Section B.2.3.2) AMP was primarily related chemistry parameters with above normal reading, such as sulfates, chlorides, nickel, and aluminum, but no specific SSCs were identified as experiencing wall thinning. The PSL Fuel Oil Chemistry (Section B.2.3.18) AMP primarily listed ARs associated with received fuel oil. No ARs showing age-related degradation of fuel oil SSCs were identified. The site-specific OE relevant to the PSL Lubricating Oil Analysis (Section B.2.3.25) AMP was primarily related to bearing/lubricating oil being an abnormal color for a variety of reasons, but none of the reasons were directly related to wall thinning of SSCs.

There are no specific health reports for the PSL One-Time Inspection AMP, since this is a new AMP. As previously stated, the PSL One-Time Inspection AMP verifies the effectiveness of the PSL Water Chemistry (Section B.2.3.2) AMP, the PSL Fuel Oil Chemistry (Section B.2.3.18) AMP, and the PSL Lubricating Oil Analysis (Section B.2.3.25) AMP. Although there are no specific program health reports for these AMPs, the Chemistry and Preventive Maintenance Programs' health reports are relevant. The Chemistry Program health reports from January 2015 through October 2020 were reviewed. The program is currently graded "Green" and has generally been graded "Green" throughout the 5-year period, with the exception of 2015 Quarter 4 and 2016 Quarters 2 and 3, which were graded "White". The issues identified by the Chemistry Program health reports included administrative issues (e.g., staff training) and open work orders related to the aging condensate polisher facility/system. The Preventive Maintenance Program health reports from January 2015 through October 2020 were also reviewed. The program is currently graded "Green" and has scored "Green" consistently throughout the 5-year period. The issues identified by the Preventive Maintenance health reports included late preventive maintenance activities for oil sampling and a late self-assessment.

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 PSL One-Time Inspection 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 PSL One-Time Inspection 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.2.3.21 Selective Leaching

Program Description

The PSL 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 PSL 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% Zn or greater than 8 % Aluminum exposed to a raw water, closed-cycle cooling water, treated water, waste water, soil, or groundwater 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. Opportunistic inspections will be performed whenever components are opened, or whenever buried or submerged surfaces are exposed. The periodic inspections are conducted at an interval of no greater than every 10 years during 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 PSL 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 PSL Selective Leaching AMP will have new governing and inspection procedures consistent with NUREG-2191, Section XI.M33.

The PSL 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 PSL Selective Leaching AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M33, “Selective Leaching”.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions. OE shows that selective leaching has been detected in components constructed from gray cast iron, ductile iron, brass, bronze, and aluminum bronze. The following external OE from NUREG-2191, Section XI.M33, are relevant to PSL:

- In March 2013, a licensee submitted an American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Section XI relief request because it had detected weeping through aluminum bronze (susceptible to dealloying) valve bodies exposed to sea water. The degraded area was characterized by corrosion debris or wetness that returned following cleaning and drying of the surface (Reference ML13091A038 and ML14182A634).

- 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).

- In September 2008, a licensee identified the dealloying of an aluminum bronze strainer drum exposed to brackish water. This was identified after an unexpected material failure occurred, during a planned maintenance evolution at an offsite repair facility. The maintenance evolution involved rigging the strainer drum into position for a machining operation. During the rigging, the strainer drum material failed at the rigging attachment point to the strainer. This failure of the strainer drum exposed the inner portion of the drum material where dealloying of the drum was visually observed during an inspection (Reference ML092400531).

- A licensee had 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).

- The PSL 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 OE demonstrates significant issues with selective leaching, further inspections and exploratory work may be required to adequately manage selective leaching.

- The PSL 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.

<u>Plant Specific Operating Experience</u>

A review of plant OE was performed, however, since the PSL Selective Leaching AMP is a new program for SLR, the amount of internal OE is not as extensive as other existing AMPs.

- Action Requests (ARs)

  A recent OE search was performed for SLR which covered a date range of October 1, 2010 through October 1, 2020. This search identified the following ARs related to selective leaching:

  - In May 2015, an AR was issued in response to NUREG-1801, Revision 2, Section XI.M33 to perform a review at PSL to determine if selective leaching had been identified and to manage it if it exists. Since industry OE indicated that selective leaching is most likely to occur in the cast iron piping used by fire protection systems, a plant specific OE review of fire protection piping for PSL was performed. This review identified that a failure of fire protection piping serving the north warehouse had occurred. The failed piping was analyzed and wall loss due to selective leaching was determined not to be a significant contributor to the pipe failure. The cause of the failure was determined to be mechanical stress. The age of the pipe was representative of the fire water distribution system for the plant.

- NRC Reviews and Inspections

  On November 20, 2015 and October 20, 2017, the NRC completed a Post-Approval Site Inspection for License Renewal at PSL Unit 1 and Unit 2, respectively, in accordance with NRC IP71003. The NRC inspectors did not identify any findings or violations of more than minor significance and determined that the overall implementation of aging management programs and time-limited aging analyses was consistent with the licensing basis of the facility. The inspectors also determined that the regulatory requirements of 10 CFR 54.37(b) were met, and commitment changes were evaluated and reported in accordance with the applicable requirements.

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 PSL Selective Leaching 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 PSL Selective Leaching 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.2.3.22 ASME Code Class 1 Small-Bore Piping

Program Description

The PSL ASME Code Class 1 Small-Bore Piping AMP is an existing AMP 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, 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.

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, or destructive examinations if the opportunity presents itself, 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 non-destructive examination (NDE), credit will be taken for each weld destructively examined equivalent to having volumetrically examined two welds.

Per NUREG-2191, Table XI.M35-1, PSL 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: PSL Unit 1 Welds

Weld Type	**Approximate Total Number**	**3%**	**Sample Size (Max 10 Welds Each Type)**		
			Volumetric	OR	Destructive
Socket (NPS-2 and smaller)	493	15	10		5
Full Penetration (Butt) (Greater than NPS-2 and less than NPS-4)	92	3	3		N/A

Table B-7: PSL Unit 2 Welds

Weld Type	**Approximate Total Number**	**3%**	**Sample Size (Max 10 Welds Each Type)**		
			Volumetric	OR	Destructive
Socket (NPS-2 and smaller)	440	14	10		5
Full Penetration (Greater than NPS-2 and less than NPS-4)	137	5	5		N/A

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.

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.

NUREG-2191 Consistency

The PSL ASME Code Class 1 Small-Bore Piping AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.M35, “ASME Code Class 1 Small-Bore Piping”.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

Turkey Point Nuclear Generating Station (PTN) SLRA
(Reference ML19191A057)**:**

- In July of 2012, a post-approval license renewal (LR) 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 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 for PTN.

  This OE was previously reviewed as part of the original PSL LR to ensure that to the extent possible, locations from the same system, pressure, and temperature environments were not selected.

- In 2012, destructive examination of Class 1 small-bore piping within the scope of the ASME Code Class 1 Small-Bore Piping AMP was performed on Unit 3. The Unit 3 inspection scope consisted of an approximate 18-inch long section of two-inch piping from the safety injection (SI) system containing a total of five socket welds (two on an elbow and three on a tee). Visual inspection, sectioning, and metallographic analysis were performed on each of the socket welds. Overall, features such as the gaps, lack of fusion and porosity noted in the welds were considered normal for fillet welds. No signs of actively growing or operationally related cracks were noted in any of the weld samples. In addition, a volumetric (UT) examination was performed on six three-inch Class 1 full penetration butt welds. No recordable indications were identified for PTN.

  The evaluation of the welds inspected as part of the PSL initial LR indicated that no unacceptable indications were identified, no evidence of service induced flaws in the welds were found, and only minor fabrication defects that are typical of socket and butt welds were found. Therefore, there is no effect on the SLR AMP for PSL.

- In 2013, destructive examination of Class 1 small-bore piping within the scope of the ASME Code Class 1 Small-Bore Piping AMP was performed for PTN Unit 4. The Unit 4 inspection scope included five two-inch elbows (three from the chemical volume and control (CVC) system and two from the SI system)) containing a total of seven socket welds. Visual inspection, sectioning, and metallographic analysis were performed on each of the socket welds. Overall, features such as the gaps, lack of fusion and porosity noted in the welds were considered normal for fillet welds. No signs of actively growing or operationally related cracks were noted in any of the weld samples. In addition, a volumetric (UT) examination was performed on five three-inch Class 1 full penetration butt welds. No recordable indications were identified for PTN.

As with the bullet above, the evaluation of the welds inspected as part of the PSL initial LR indicated that no unacceptable indications were identified, no evidence of service induced flaws in the welds were found, and only minor fabrication defects that are typical of socket and butt welds were found. Therefore, there is no effect on the SLR AMP for PSL.

Surry Power Station (SPS) SLRA (Reference ML20052F520)**:**

- 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.

  Since the indications described above were due to a fabrication issue specific to only the ‘B’ loop cold leg drain and not related to thermal fatigue there is no effect on the SLR AMP for PSL.

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 relevant License Event Reports (LERs) was performed related to Class 1 small-bore piping.

- **Hatch:** Per LER 2-2008-003-1 (Reference ML081920188), systems within the ASME Class 1 boundary were reviewed for lines which are small-bore, not isolable, and SS. 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.

- **Turkey Point:** LER 2008-003-00 (Reference ML082890197) documented repair of a RCP test connection line.

- **Browns Ferry:** LER 2008-002-01 (Reference ML090860775) documented repair of an un-isolatable leak on an instrument line by weld overlay. Inservice examination requirements of the weld overlay were added to the ISI program. Remaining Unit small-bore instrument nozzle safe ends were ultrasonically examined with no further recordable indications.

- **Susquehanna:** LER 2012-007-01 (Reference ML123250703) documented modification and repair of a chemical decontamination connection of a recirculation pump suction line. Additional modifications, inspections, and corrective actions were planned to be taken.

- **Hope Creek:** LER 2005-002-00 (Reference ML051540027) documented modification and repair of recirculation loop connections. Review of all other similar connections to the reactor recirculation loops was performed with all NDE inspection results found to be acceptable.

- **Peach Bottom:** LER 2005-003-00 (Reference ML053110153) documented replacement of a welded joint on an equalizing line for a residual heat removal (RHR) air-operated valve. An extent of condition was performed for similar welds on Unit 3, which required additional repairs on both of the RHR loops.

- **Peach Bottom:** LER 2017-001-00 (Reference ML17355A003) documented replacement of a section of Class 1 small-bore piping and fitting instrument line on a recirculation pump. Instrument lines connected to the suction and discharge of both recirculation pumps with similar configuration and subject to vibration were also replaced during the next refueling outage. The new welds were performed with a 2:1 profile, which reduces susceptibility to vibration-induced failures.

<u>Information Notice (IN) 2007-21 Supplement 1:</u>

- IN 2007-21 Supplement 1, “Piping wear due to interaction of flow-induced vibration and reflective metal insulation” was published December 2020. The supplement to this IN updated abrasive wear between SS reflective metal insulation (RMI) end caps and ASME Class 2 piping found in Catawba to also include industry OE from other sites that identified similar RMI fretting of Class 1 piping.

- PSL evaluated this industry OE in February 2021, concluding that PSL has zero evidence of such adverse effects that have occurred at other units in the industry. The bases for this conclusion are results from extensive walkdowns of RMI-insulated ASME piping at PSL that were conducted as part of the GSI-191 project for both Units 1 and 2. No locations were identified where it was suspected that wear on ASME piping had occurred due to interaction of flow-induced vibration and RMI insulation.

Plant Specific Operating Experience

- A review of the eight inspections for Unit 1 and the ten inspections for Unit 2 selected for initial LR indicated that no unacceptable indications were identified, no evidence of service induced flaws in the welds were found, and only minor fabrication defects that are typical of socket and butt welds were found.

- LER-2014-001-01 (Reference ML15043A156): A Unit 2 safety injection tank (SIT) discharge piping vent valve was replaced during a refueling outage. Approximately three months later, frequent replenishment of the SIT and an upward radiation monitor trend were indicative of a leak from the SI system. The leak was confirmed to be on a one-inch pipe between the SIT and the vent valve that was replaced during the refueling outage. Unit 2 was shut down to repair the leak.

  It was determined that the original repair and replacement of the vent valve was not performed as prescribed in the work order documents, which resulted in failure of the pipe nipple upstream of the vent valve. In addition, neither maintenance nor the NDE inspector verified the dimensions of the field-cut inlet pipe nipple before the vent valve was welded as required by procedures.

  Corrective actions resulting from the root cause evaluation included the following:

  - Modification of the “Weld Coordinator” software program to include hold points in weld travelers for dimension verification by the NDE inspector for Class 1, 2, and 3 piping.

  - Revision of welding work control procedures to ensure applicable weld travelers incorporate the requirements to use applicable NDE procedures related to ASME Section III and ANSI B31.1 for butt and fillet weld visual examinations.

  - Revision of maintenance training to emphasize the findings of the root cause evaluation, the impact to the plant of the event, the importance of using human performance tools when complying with work documents, and the importance of ensuring that condition reports are addressed by the appropriate work document.

- LER-2017-001-00 (Reference ML17093A948) provided details of a required shut down of Unit 1 due to a reactor coolant pressure boundary leak within a RCP lower seal heat exchanger, which required entering a Technical Specification action statement for repair. The seal heat exchanger, seal package, and tubing components involved are part of a singular component and the leak occurred internal to the seal package. Therefore, individual socket welds, which are the scope of this ASME Code Class 1 Small-Bore Piping AMP, were not involved. The flaw was removed, weld repair completed, and the Unit returned to service. Inspections of all in-service and spare Unit 1 and Unit 2 RCP lower seal heat exchangers were performed and no additional flaws were identified as a result of these inspections.

As part of a follow-up root cause analysis, the most probable cause was determined to be a condition in the lower seal heat exchanger design which permitted stresses that approached or exceeded the yield strength of the assembly tubing during torquing of the component cooling water (CCW) flanges. The resultant plastic deformation and associated flow formation caused low stress high cycle fatigue failure of the weld joint.

An additional corrective action identified as a result of the root cause analysis was development of methods to reduce the stress on the RCP lower seal heat exchanger tubing during installation activities.

The site-specific OE for ASME Code Class 1 Small-bore Piping indicates that no age-related cracking has been identified, thus PSL remains a Category A plant per NUREG-2191, Table XI.M35-1.

Program Assessments and Evaluations

Several post-approval NRC reviews have been performed since 2012. 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 contain the appropriate LR 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.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The PSL 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 PSL ASME Code Class 1 Small-Bore Piping AMP provides 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.2.3.23 External Surfaces Monitoring of Mechanical Components

Program Description

The PSL External Surfaces Monitoring of Mechanical Components AMP is an existing AMP that was formerly part of the PSL Systems and Structures Monitoring Program.

The PSL External Surfaces Monitoring of Mechanical Components AMP is a condition monitoring AMP that manages loss of material, cracking, hardening or loss of strength (of elastomeric and polymeric components), reduction of heat transfer due to fouling (air to fluid heat exchangers), and blistering. The PSL 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.

For 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 will be credited for managing: (a) loss of material and cracking of internal surfaces for metallic components, or (b) hardening or loss of strength of internal surfaces for elastomeric components. The material and environment combinations where external examinations could be credited to manage the aging effects of the internal surfaces of components. Those specific combinations are:

(a) Loss of material and cracking of internal surfaces of metallic components where the internal environment of the component is air:

- Containment cooling system – the carbon steel damper housings, containment fan cooler housings, and valve bodies, and the SS thermowells;

- Containment spray system – nickel alloy and SS piping and piping components with uncontrolled indoor air inside it and SS nozzles and strainers with uncontrolled indoor air inside;

- Containment isolation components system – all carbon steel and SS components with an internal environment of air;

- Containment post-accident monitoring system – all components with an internal environment of air;

- Component cooling water system – all components managed by this program with an internal environment of air except for the surge tank (because of the potential for areas of the tank internals to be exposed to both air and closed treated water environments);

- Diesel generators and support systems – all aluminum, carbon steel, and SS components managed by this program with an internal environment of air;

- Fire protection and service water systems – all aluminum components managed by this program, carbon steel accumulators, flame arrestors, metallic flexible hoses with an internal environment of air, piping and valve bodies where the internal and external portions of the pipe are exposed to an air environment (not including the RCP oil collection components where internal surfaces may have a coating of lubricating oil applied over time), and galvanized steel piping where the internal and external portions of the pipe are exposed to an outdoor air environment;

- Instrument air and bulk gas supply systems – all receivers, piping, thermowells, and valve bodies managed by this program upstream of the air dryers (not filters, silencers, or dryers because of the potential for air flow to affect the internal surfaces of the filter);

- Sampling system – all components managed by this program with an internal environment of air;

- Ventilation system – all fan housings, thermowells, and valve bodies, SS piping, and carbon steel piping and piping components where the internal and external portions of the pipe are exposed to an air environment;

- Auxiliary feedwater and condensate system – all carbon steel piping and valve bodies where the internal and external portions of the pipe are exposed to an air environment;

(b) Hardening or loss of strength for the internal surfaces of elastomeric materials:

- Containment cooling system – all flex connections managed by this program;

- Instrument air and bulk gas supply systems – all flexible hoses managed by this program;

- Ventilation system – all flex connections managed by this program;

Periodic visual inspections of metallic, polymeric, and elastomer components are conducted. 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 and elastomers, physical manipulation to detect hardening or loss of strength will be used to augment the visual inspections conducted under this program. 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.

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 susceptible SS, copper alloy, and aluminum components. Periodic visual inspections or surface examinations are conducted to manage cracking in metallic components every 10 years during the SPEO. Component surfaces that are insulated and may be exposed to condensation and insulated outdoor components are inspected at least every 10 years or more frequently as required by plant specific OE. Surfaces that are not readily visible during plant operations and refueling outages are inspected opportunistically when made accessible or within an interval that would provide reasonable assurance that the components' intended functions are maintained. Other inspections are performed at a frequency not to exceed one refueling cycle.

Surface examinations or VT-1 examinations for managing cracking and inspections for insulated components in an outdoor environment or that may be exposed to condensation in an indoor environment are conducted on 20 percent of the surface area of the component 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 for the population of components included in that inspection.

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 will be initiated for conditions identified during the walkdowns to provide reasonable assurance that loss of component intended functions does not occur. The PSL External Surfaces Monitoring of Mechanical Components AMP procedures utilize guidance from the EPRI Technical Report TR-1007933 (Reference 1.6.42), "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 the issue is entered into the corrective action program to perform an assessment and document the appropriate actions and recommendations; which may include the adjustment of inspection frequencies.

NUREG-2191 Consistency

The PSL External Surfaces Monitoring of Mechanical Components AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M36, "External Surfaces Monitoring of Mechanical Components".

Exceptions to NUREG-2191

None.

Enhancements

The PSL External Surfaces Monitoring of Mechanical Components 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	• Revise procedure to indicate the material and environment combinations where external examinations could be credited to manage the aging effects of the internal surfaces of components. • Revise the PSL External Surfaces Monitoring of Mechanical Components AMP procedure to incorporate the aging management activities currently performed for external corrosion of insulated piping at PSL.
3. Parameters Monitored or Inspected	• Revise procedures to ensure all components made of SS, aluminum, or copper alloys with greater than 15% Zn or 8% Al inspected by this program will have periodic visual or surface examinations conducted to manage cracking. • Revise procedure to monitor the aging effects for elastomeric and flexible polymeric components through a combination of visual inspection and manual or physical manipulation of the material. Manual or physical manipulation of the material will include touching, pressing on, flexing, bending, or otherwise manually interacting with the material. The purpose of the manual manipulation will be 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. Flexing of polymeric components (e.g., expansion joints) 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) will be conducted to detect potential reduction in impact strength as indicated by a crackling sound or surface cracks when flexed. Examples of inspection parameters for elastomers and polymers will include: o Surface cracking, crazing, scuffing, and dimensional change (e.g., “ballooning” and “necking”), o Loss of thickness, o Discoloration (evidence of a potential change in material properties that could be indicative of polymeric degradation), o Exposure of internal reinforcement for reinforced elastomers, o Hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate to manipulation.
4. Detection of Aging Effects	• Revise procedure to specify that this program will also manage hardening or loss of strength, loss of preload for

Element Affected	Enhancement
	heating, ventilation, and air conditioning (HVAC) closure bolting, and blistering using visual inspections. In addition, physical manipulation will be used to manage hardening or loss of strength and reduction in impact strength. • Revise procedure to specify that, when required by the ASME Code, inspections will be conducted in accordance with the applicable code requirements. And, when non-ASME Code inspections and tests are required, inspections will follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, and presence of protective coatings. Inspections, except those for cracking and under insulation, will be performed every refueling outage. • Revise procedures to ensure that periodic visual inspections or surface examinations will be conducted on components made of SS, aluminum, or copper alloys with greater than 15% Zn or 8% Al to manage cracking every 10 years during the SPEO and other inspections will be performed at a frequency not to exceed one refueling cycle. 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 provide reasonable assurance that the components’ intended functions are maintained. • Revise procedure to specify that, when inspecting to manage cracking of a component’s material, either surface examinations conducted in accordance with plant-specific procedures or ASME Code Section XI VT-1 inspections (including those inspections conducted on non-ASME Code components) are conducted on each component inspected. An inspection requires that at least 20% of the surface area of the component is inspected, unless the component is measured in linear feet, such as piping. Any combination of 1-foot length sections and components can be used to meet the recommended extent of 20% of the population of materials and environment combinations, with a maximum of 25 inspections required in each population. An inspection of a component in a more severe environment may be credited as an inspection for the specified environment and for the same material and aging effects in a less severe environment (e.g., an outdoor air environment is more severe than an indoor uncontrolled air environment which is more severe than an indoor controlled air environment, assuming that there are no borated water leaks in the indoor environments). • Revise procedure to specify that, when inspecting insulated components in an outdoor environment or that may be exposed to condensation in an indoor environment, that the population and sample sizes used for inspections will be

Element Affected	Enhancement
	determined based on the material type (e.g., steel, SS, copper alloy, aluminum) and environment (e.g., air outdoor, air accompanied by leakage) combination. 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 twenty-five 1-foot axial length sections and components for each material type is inspected, with a maximum of 25 inspections required in each population. • Revise procedure to ensure that visual inspections 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. 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. 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. The sample size for manipulation will be at least 10% of available surface area. • Revise procedure to indicate that the following alternatives to removing insulation after the initial inspection will be acceptable: a. Subsequent inspections may consist of examination of the exterior surface of the insulation with sufficient acuity to detect indications of damage to the jacketing or protective outer layer (if the protective outer layer is waterproof) of the insulation when the results of the initial inspections meet the following criteria: i. No loss of material due to general, pitting, or crevice corrosion beyond that which could have been present during initial construction is observed during the first set of inspections, and ii. No evidence of SCC is observed during the first set of inspections. If: (a) the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or jacketing, (b) there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), or (c) the protective outer

Element Affected	Enhancement
	layer (where jacketing is not installed) is not waterproof, then periodic inspections under the insulation should continue as conducted for the initial inspection. b. Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of corrosion under insulation is low for tightly adhering insulation. Tightly adhering insulation is considered to be a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope piping that has tightly adhering insulation is visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections are not credited towards the inspection quantities for other types of insulation.
5. Monitoring and Trending	• Revise procedure to specify that 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.
6. Acceptance Criteria	• Revise procedure to include evaluation and acceptance guidance from EPRI TR-1009743 (Reference 1.6.43), "Aging Identification and Assessment Checklist," for visual/tactile inspections where appropriate.
7. Corrective Actions	• Revise procedures to specify that inspections to detect cracking in aluminum, SS, and applicable copper alloy components will have additional inspections conducted if one of the inspections does not meet the 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. The number of increased inspections will be determined in accordance with the site's corrective action process; however, 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 is inspected, whichever is less. The additional inspections are completed within the interval in which the original inspection was conducted. If 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. Additional samples will be inspected for any recurring degradation to provide

Element Affected	Enhancement
	reasonable assurance that corrective actions appropriately address the associated causes. The additional inspections include populations with the same material, environment, and aging effect combinations at both Unit 1 and Unit 2. • Revise procedures to require that any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, will have their inspection frequencies adjusted as determined by the corrective action program.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

- In 2017, NRC inspection reports identified ineffectiveness and an adverse trend related to the Turkey Point External Surfaces Monitoring of Mechanical Components AMP. In response, a fleet corrosion monitoring action program procedure was developed. The PSL procedure was reviewed to clarify the requirements and strategies to monitor and control externally initiated general and localized corrosion of SR equipment and piping in outdoor or exposed environments.

- Industry OE identified an ineffective AMP at Prairie Island Nuclear Plant as contributing to the failure of a component in 2018. PSL wrote an AR in January 2019 to track incorporation of the industry OE at the site. The AR required benchmarking of site OE, assessing training and knowledge requirements for walkdowns, and a review of forms used to guide walkdowns. As a result of the reviews, another AR was written to change plant procedures to ensure that existing conditions are reviewed prior to performing license renewal walkdowns. The procedure revision and all actions associated with the ARs were completed by October 2019.

Plant Specific Operating Experience

The following summary of site-specific OE (which includes review of corrective actions and NRC inspections) provides examples of how PSL is managing aging effects associated with the PSL External Surfaces Monitoring of Mechanical Components AMP.

- In November 2011, the fire protection piping supplying the nuclear training center suppression system was identified as corroded. The identified corrosion was located at the floor level upstream of a fire water supply isolation valve. The affected piping is located inside the air conditioning equipment room within the south side of the nuclear training center. The corroded piping was repaired. Although this fire water piping is outside the scope of SLR, it was included because the material and environment are similar to other in-scope components.

- In June 2013, Nuclear Oversight identified that the small bore Unit 2 turbine lubricating oil deluge system piping had rust and ongoing loss of material due to corrosion. This small bore piping and associated hardware needed to be properly prepared and recoated as soon as possible prior to the loss of material progressing to the point that components would need to be replaced. The piping was recoated as recommended.

- In January 2018, following the completion of a license renewal walkdown, a question was identified regarding the ability of a walkdown at a 5-year frequency to adequately manage the aging of the outside portions of the component cooling water system and the auxiliary feedwater and condensate system. A recommendation was made to change the frequency to 18 months. The actions associated with updating the Systems and Structures Monitoring Program to change the frequency of the walkdowns associated with the systems in question was completed in April 2018.

- In March 2018, the 1A component cooling water return header coatings showed signs of breakdown and corrosion cells. The corrosion cells have not resulted in serious metal loss. A WR and a WO were written to repair the corroded pipe and coatings. The repairs are still in progress.

- In January 2020, pitting was identified on the 1B intake cooling water supply header. Work orders completed the repairs in July 2020.

- In April 2020, a throughwall leak was identified on the 1B intake cooling water header. The leakage was estimated to be 100 gallons per minute, which was within the margin for leakage of the intake cooling water system of 1580 gallons per minute. The leak was covered and then plugged to protect the surrounding equipment. The piping was repaired in June 2020. Additional non-destructive examinations were performed on 5 additional locations to determine extent of condition. The results of the additional examinations show several areas with reduced wall thickness readings. Follow-on examinations at the additional locations with reduced wall thickness readings were performed for comparison and trending. Repair activities for the piping locations with reduced wall thickness readings are being tracked. Some of the repair work is being planned to start in 2021. All above ground intake cooling water piping in the scope of SLR is planned to be replaced with AL6XN piping.

- There are additional examples of external surface plant specific operating experience presented under the PSL Fire Water AMP (B.2.3.16).

Program Assessments and Evaluations

- In February 2010, a readiness assessment for life extension was performed. The Systems and Structures Monitoring Program was among the areas reviewed. The only finding in 2010 associated with the Systems and Structures Monitoring Program was that the administrative procedure to support the program had not been fully developed. This issue was assigned an AR to track its completion. The procedure was generated to support the original license renewal implementation and is used for license renewal system walkdowns.

- In March 2015, a focused self-assessment was performed to determine the readiness for the license renewal implementation NRC IP71003 phase II inspections. The Systems and Structures Monitoring Program did not have any enhancements or areas for improvement identified during the self-assessment. The engineers that performed walkdowns for the Systems and Structures Monitoring Program were credited with a strength during the assessment for their low threshold to generate ARs when issues were identified.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL External Surfaces Monitoring of Mechanical Components AMP were identified.

The PSL 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 PSL External Surfaces Monitoring of Mechanical Components 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.2.3.24 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new AMP that will manage loss of material, cracking, blistering, wall thinning, reduction of heat transfer due to fouling, flow blockage, and hardening or loss of strength of polymeric materials. Applicable environments will include air, diesel exhaust, raw water, treated water, waste water, fuel oil, and lubricating oil. Some inspections and activities within the scope of the new AMP were previously performed by the PSL 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 and loss of material of SS, copper alloy (>15% Zn), and aluminum components. Aging effects associated with items (except for elastomers) within the scope of the PSL Open-Cycle Cooling Water AMP (Section B.2.3.11), the PSL Closed Treated Water Systems AMP (Section B.2.3.12), and the PSL Fire Water System AMP (Section B.2.3.16) are not managed by this AMP.

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 25 components per unit will be inspected for the in-scope aging effects. Where the sample size will not be based on the percentage of the population, a reduction in the total number of inspections to 19 components inspected per unit is acceptable for the following material and environment combinations because site OE has not indicated a difference in aging effects between the two units for the environments listed:

- Air – indoor uncontrolled environment and aluminum, carbon steel, SS, carbon steel with SS internal cladding, cast iron, nickel alloy, and elastomer materials;
- Air – outdoor environment and aluminum, carbon steel, galvanized steel, and SS materials;
- Raw water environment for systems supplied by the same raw water supply (i.e., intake cooling water systems and fire protection systems) and carbon steel, copper alloy, galvanized steel, and SS.

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 procedure 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.

Uncontrolled indoor air environments on both the internal and external surfaces are considered to have similar aging effects such that the conditions on the external surfaces would be representative of the effects on the internal surfaces. Outdoor air environments on both the internal and external surfaces are considered to have similar aging effects such that the conditions on the external surfaces would be representative of the effects on the internal surfaces. The following components in the systems that have aging effects managed by the PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP can credit external inspections performed by the PSL External Surfaces Monitoring of Mechanical Components AMP (Section B.2.3.23) to manage the listed aging effects:

- Loss of material and cracking of internal surfaces of metallic components for:
    - The SS thermowells and all carbon steel components in the containment cooling system that are managed by this program;
    - The SS nozzles and strainers and the nickel alloy and SS piping and piping components with an internal environment of uncontrolled indoor air in the containment spray system;
    - All carbon steel and SS components managed by this program in the containment isolation components system;
    - All components managed by this program in the containment post-accident monitoring system and the sampling system;
    - All components managed by this program except the surge tank in the component cooling water system;
    - The SS housings, piping, thermowells, and valve bodies managed by this program and all aluminum, carbon steel, and cast iron components managed by this program in the diesel generators and support systems;
    - All aluminum components managed by this program, the carbon steel accumulators, carbon steel and SS drip pans, flame arrestors, and metallic flexible hoses, the piping and valve bodies where the internal and external portions of the pipe are exposed to an air environment (not including the RCP oil collection components), and the galvanized steel piping where the internal and external portions of the pipe are exposed to an outdoor air environment in the fire protection and service water systems;

- All receivers, piping, thermowells, and valve bodies managed by this program (but not filters, silencers, or dryers) in the instrument air and bulk gas supply systems;
- All fan housings, thermowells, valve bodies, SS piping, and carbon steel piping and piping components where the internal and external portions of the pipe are exposed to an air environment in the ventilation system;

- Hardening or loss of strength for the internal surfaces of elastomeric materials:
  - All flex connections managed by this program in the containment cooling system and ventilation system;
  - All flexible hoses managed by this program in the instrument air and bulk gas supply systems.

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.

This AMP is also used to manage cracking due to stress corrosion cracking in aluminum and 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.

The PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will have new governing inspection procedures consistent with NUREG-2191, Section XI.M38.

The PSL 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 PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be consistent without exception to 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

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

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. PSL 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 addressed below. The review was broad and detailed enough to detect instances of aging effects that have occurred repeatedly. Repeatedly occurring aging effects (i.e., recurring internal corrosion) meeting the criteria 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,” were identified for metallic components exposed to an intake cooling water environment. The recurring internal corrosion recommendations related to augmenting aging management activities are addressed in the Open-Cycle Cooling Water AMP (Section B.2.3.11).

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

This is a new program but the following related plant specific OE is applicable. The examples listed illustrate that routine visual exams performed during maintenance activities have successfully identified and corrected age-related degradation.

- Intake cooling water piping that is not SR had internal pitting in February 2011. The locations of the pipe wall were evaluated. Work orders repaired the corrosion cells in March 2011.
- Corrosion was found on the ventilation screens for a diesel generator in December 2011. Work orders replaced and painted the screens in December 2011.
- Deluge heads were clogged in May 2012. The heads were removed and associated piping was flushed thoroughly to remove any scale. The system

was retested without any clogging noted in May 2012. An evaluation was performed to determine if any trends in the heads that were clogged for the deluge system were apparent. No trend could be identified.

- Internal surface corrosion was found inside the shield building ventilation system ducting in April 2015. The rust was only on the surface without metal degradation. Work orders performed repairs on the duct and other nearby ducts and installed vapor blocks to mitigate future corrosion.

- Corrosion was found on the pipe and flange of the discharge of the instrument air compressor in September 2015. The corrosion occurred due to high humidity and high velocity hot air from the compressor heads. The piping was determined to be above the minimum wall thickness. The piping was replaced as part of the design changes that replaced the instrument air compressors in December 2017.

- Corrosion was observed on the interior and exterior of fan housings and dampers in March 2017. The corrosion did not impact the structural integrity of the components. A work request/work order was written to monitor and track the condition while planning repairs to be scheduled and implemented during normal system work windows based on system engineering recommendations.

- Small tears were found in an expansion joint in the fuel pool exhaust system during an inspection in December 2018. The required repairs were minor and were completed in December 2018.

- Debris (paint chips/tank sludge) was observed at the bottom of the Unit 1 head tank associated with the instrument air compressor emergency cooling system in April 2019. The debris could have possibly moved to the radiator, preventing proper cooling flow. The inside of the head tank was cleaned and an evaluation was performed to determine if cleaning was needed on the Unit 2 tank. An engineering change has been written to replace the head tank with a SS tank without internal coatings.

- Through wall holes were identified in a flow control valve for the South Control Room outside air intake in April 2020. A work order and an engineering change performed repairs in May 2020.

- Some of the blades on the dampers for the drum type supply air diffusers were found to have broken free from the frame in October 2020. A walkdown was performed on all 24 drum type diffusers to determine if any of the other dampers were degraded. Although rusty, the remaining dampers had no broken damper blades. A work order is in progress to replace the dampers on all the drum type diffusers in the duct.

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 PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components 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 PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components 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.2.3.25 Lubricating Oil Analysis

Program Description

The PSL Lubricating Oil Analysis AMP is an existing AMP that includes activities previously performed as part of plant predictive maintenance. The PSL 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 PSL Lubricating Oil Analysis AMP maintains lubricating 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. There are no components utilizing hydraulic oil in the scope of the PSL Lubricating Oil Analysis AMP.

Although the PSL Lubricating Oil Analysis AMP is based on obtaining and analyzing oil samples, the AMP will be augmented to manage the effects of aging for SLR. Verification of the effectiveness of the PSL Lubricating Oil Analysis AMP will be conducted by the PSL One-Time Inspection AMP (Section B.2.3.20) on selected components at susceptible locations in lubricating oil environments.

The PSL Lubricating Oil Analysis AMP monitors oil system parameters (such as water, wear particles, oxidation, viscosity, fuel dilution, fuel soot, nitration, and glycol) to provide reasonable assurance that the oil will be maintained 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 parameter 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 PSL Lubricating Oil Analysis AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M39, "Lubricating Oil Analysis".

Exceptions to NUREG-2191

None.

Enhancements

The PSL Lubricating Oil Analysis 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	• 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 OE associated with oil systems may also be used to adjust the schedule for periodic sampling and testing, when justified by prior sampling results.
6. Acceptance Criteria 7. Corrective Actions	• Ensure guidance indicates that 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

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

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.

Plant Specific Operating Experience

- Action Requests (ARs)
  - In November 2014, upper and lower motor oil samples were taken for analysis following increased vibration of the 1B condensate pump. An adverse condition monitoring plan was initiated, which involved periodic oil sampling and continuous vibration monitoring. The inboard and outboard bearing oil was replaced.
  - In May 2015, a color change was detected during routine oil sampling of the 1A condensate pump motor. The oil sample indicated motor lower bearing degradation. The oil was changed; however, no work was performed due to the motor being sent for overhaul. Both the 1A and 1B condensate pumps were considered in a degraded condition and a condition monitoring plan was put into place to monitor motor vibrations. A long-term corrective action was put into place and all three of the condensate pump motors were refurbished during the Fall 2016 refueling outage.
  - In January 2017, an oil sample from the 2A turbine cooling water (TCW) pump inboard bearing had dark color, increased wear particle concentration, an unusual increased water content, and a small temperature increase. The data indicated a degraded pump inboard bearing. The inboard bearing oil reservoir was flushed, cleaned, and

refilled with new oil. The 2A TCW pump inboard bearing was inspected and repaired. Additional activities were initiated to clean and inspect the 2A and 2B TCW pump inboard and outboard oil catch basins and drain lines to assist in prevention of water accumulation from impacting bearing lube oil, as well as to cover the 2A TCW pump toe rail opening to prevent water from draining directly over the pump.

- In September 2019, a 1A low pressure safety injection pump outboard motor oil sample was found to have questionable color, as well as some suspended particles. The oil was drained, flushed, and replaced. As noted in the follow-up actions of the AR, the oil sample results confirmed a greenish tint with no significant bearing degradation particles and tested parameters were met. The water content and viscosity were found to be normal and the wear particle concentration was within the normal band. Operational checks of the pump following the oil replacement were acceptable.

- In May 2020, a routine oil sample of the 2A auxiliary feedwater pump outboard oil reservoir depicted increased wear particle concentration and darker color. Analysis indicated that the particulate was older break-in wear likely from previous thrust bearing work that was completed during an earlier refueling outage and determined not to be a significant concern for performing the pump intended function. PSL OE depicted similar dark oil increased particulate occurrences on pump reservoirs after bearing or seal work that only required oil replacement and additional sampling to clean up the reservoirs in lieu of any required rework. A sample was obtained and the outboard bearing oil drained, flushed, and refilled.

  Although some of the above plant-specific OE are not related to equipment included with the scope of the Lubricating Oil Analysis AMP, they depict examples of the identifying and correcting issues associated with lubricating oil, such that components within the scope of the Lubricating Oil Analysis AMP that are exposed to lubricating oil will continue to perform their intended function through the SPEO.

- Program Owner Discussions

  - On December 4, 2020, an interview was held with the PSL Lubricating Oil Analysis AMP owner. The AMP Owner has been the owner of lubricating oil analysis for the past 13 years and noted that this AMP is based on existing activities which are part of a mature sampling program. Currently, PSL samples for water content, among other parameters. ARs are written for any adverse findings and evaluated in the corrective action program and the program updated if required as a result of the corrective action. There is no individual health report for this program. No ARs resulting in program enhancements or program failures or weaknesses were identified. In addition, no long-term water accumulation issues in diesel or lubricating oil environments, repeat failures signifying recurring internal corrosion, or any components within the scope of the program having experienced significant degradation were identified.

- System/Program Health Reports
    - Lubricating oil analysis is currently part of the Periodic Surveillance and Preventive Maintenance Program; therefore, health reports for the Preventive Maintenance Program provides insight into the health of activities that will be credited for the PSL Lubricating Oil Analysis AMP.

      The Preventive Maintenance Program is currently GREEN and has maintained a GREEN status for the past five years. The only item related to lubricating oil was late preventive maintenance activities (PMs) of oil samples.

Program Assessments and Evaluations

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings were identified related to the PSL Lubricating Oil Analysis AMP.

The PSL Lubricating Oil Analysis 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 PSL Lubricating Oil Analysis 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.2.3.26 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

Program Description

The PSL Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP, formerly the PSL Metamic® Insert Surveillance Program, is an existing AMP that is implemented to provide reasonable assurance that degradation of the neutron-absorbing material used in spent fuel pools, that could compromise the criticality analysis, will be detected. This AMP relies on periodic inspection, testing, monitoring, and analysis of the criticality design to provide reasonable assurance that the required 5 percent subcriticality margin is maintained during the SPEO. This AMP consists of inspecting the physical condition of the neutron-absorbing material, such as visual appearance, dimensional measurements, weight, geometric changes (e.g., formation of blisters, pits, and bulges), and boron areal density as observed from coupons or *in situ*. Other testing, monitoring, and analysis activities performed as part of this AMP are described below.

This AMP addresses the aging management of the credited neutron-absorbing materials, (i.e., Metamic® inserts and Boral® panels) within the PSL Spent Fuel Pools (SFPs). Control element assemblies (CEAs) are credited in the SFP criticality analysis; however, they are not within the scope of this AMP. PSL does not credit Boraflex as a neutron-absorber; therefore, there is no need to establish a PSL Boraflex Monitoring AMP, as identified in NUREG-2191, Section XI.M22.

This AMP monitors and manages aging effects associated with neutron-absorbing components/materials that are credited for the SFP criticality analysis. The only such credited neutron-absorbing materials inside the SFP, other than the CEAs which are not assigned an AMP, are the Metamic® inserts in Region II of the spent fuel pool and the Boral® panels in the cask pit rack. Prior to the PEO, the Metamic® insert surveillance portion of this AMP had been implemented by the Metamic® Insert Surveillance Program; however, the existing AMP does not include a surveillance program for the Boral® panels in the SFP cask area. Therefore, the existing AMP will be enhanced for purposes of SLR to manage the Boral® panels.

For these neutron-absorbing materials, gamma irradiation and/or long-term exposure to the wet pool environment may cause loss of material and changes in dimension (such as gap formation, formation of blisters, pits, and bulges) that could result in loss of neutron-absorbing capability of the material. The parameters monitored as part of this AMP include the physical condition of the neutron-absorbing materials, such as in-situ gap formation, geometric changes in the material (formation of blisters, pits, and bulges) as observed from coupons or in situ, and decreased boron-10 areal density, etc. The parameters monitored are directly related to determination of the loss of material or loss of neutron absorption capability of the material(s).

The pertinent Metamic® insert surveillance procedure performs visual inspections, weight testing, dimensional measurements, and neutron attenuation testing. Visual inspections on the selected Metamic® inserts monitor for anomalies such as cracking, corrosion, pitting, and other surface defects (e.g., bulging) or geometric changes. Weight testing on the selected number of Metamic® inserts determines if the inserts are still within their nominal weight range. The selected Metamic® insert panels also have their length, width, and thickness measured to ensure the dimensions remain within their nominal ranges. Neutron attenuation testing is performed on the selected number of Metamic® coupons, which determines if any significant change in the boron-10 areal density has occurred.

The Boral® panel and Metamic® insert surveillance procedure selects panels and inserts that are to be inspected to ensure they are representative of the neutron absorber materials in the pool. The measurements from periodic inspections and analysis are compared to baseline information or prior measurements and analysis for trend analysis. The approach for relating the measurements to the performance of the SFP neutron absorber materials is specified, considering differences in exposure conditions, vented/nonvented test samples, and spent fuel racks, etc. To ensure the SFP is maintained within the criticality analysis, the Boral® panel and Metamic® insert surveillance procedure will include acceptance criteria that verifies the 5 percent subcriticality margin in maintained.

Corrective actions are to be initiated if the results from measurements and analysis indicate that the 5 percent subcriticality margin cannot be maintained because of current or projected future degradation of the neutron-absorbing material. Corrective actions may consist of providing additional neutron-absorbing capacity with an alternate material, or applying other options, which are available to maintain the subcriticality margin.

NUREG-2191 Consistency

The PSL Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M40, “Monitoring of Neutron-Absorbing Materials Other Than Boraflex”.

Exceptions to NUREG-2191

None.

Enhancements

The PSL Monitoring of Neutron-Absorbing Materials Other Than Boraflex 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	Create a new surveillance procedure to manage aging effects associated with the Boral® panels in the SFP’s cask area.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Create a governing surveillance procedure to manage aging effects associated with the Boral® panels in the SFP's cask area. This procedure is required to monitor for loss of material and changes in dimension that could result in loss of neutron-absorbing capability of the Boral® panels. The parameters monitored are associated with the physical condition of the Boral® panels and include *in-situ* gap formation, geometric changes (such as blisters, pits, and bulges) as observed from coupons or *in situ*, and decreased boron-10 areal density, etc. The parameters monitored are directly related to determination of the loss of material or loss of neutron absorption capability of the Boral® panels.
4. Detection of Aging Effects	Update the Metamic® insert surveillance procedure to state that the frequency of the Metamic® insert inspection and testing, throughout the SPEO, depends on the condition of the neutron-absorbing material and is determined and justified with PSL-specific OE, and for each Metamic® insert selected for surveillance, the maximum interval between each inspection and between each coupon test is not to exceed 10 years, regardless of OE. The new Boral® panel surveillance procedure is required to use coupon and/or direct *in-situ* testing of the Boral® panels to identify their associated loss of material and degradation of neutron-absorbing capacity. Such testing includes periodic verification of boron loss through boron-10 areal density measurement of coupons or through direct *in-situ* techniques. In addition to measuring boron content, the testing is required to s be capable of identifying indications of geometric changes in the material (blistering, pitting, and bulging). The frequency of the inspection and testing depends on the condition of the neutron-absorbing material and is determined and justified with plant-specific OE by the licensee. The maximum interval between these inspections is not to exceed 10 years, regardless of OE. The initial Boral® testing and inspections must be performed and completed at least 6 months prior to the SPEO. This initial inspection and testing ensure that the 10-year inspection and testing interval is not immediately exceeded on first day of the SPEO.

Element Affected	Enhancement
5. Monitoring and Trending	Update the Metamic® insert surveillance procedure to state that the observations and measurements from the periodic inspections and coupon testing are compared to baseline information or prior measurements and analyses for trending analysis, projecting future degradation, and projecting the future subcriticality margin of the spent fuel pool (SFP). This trending of inspection and coupon testing measurements, for the purpose of projecting future Metamic® insert degradation and SFP subcriticality margins, must use an adequate representation of the entire Metamic® insert population and consider differences in each Metamic® insert or coupon's exposure conditions, differences in the spent fuel racks. The new Boral® panel surveillance procedure is required to compare the measurements from periodic inspections and analysis to the baseline information or prior measurements and analysis for trending analysis. In addition to comparing the inspection and testing measurements to the specified acceptance criteria, this procedure trends the measurements to project future Boral ® panel degradation and SFP subcriticality margins. The degradation trending must be based on samples that adequately represent the entire Boral® panel population, and the trending must consider differences in sample exposure conditions, differences in spent fuel cask racks, and possibly other considerations.
6. Acceptance Criteria	The new Boral® panel surveillance procedure's acceptance criteria for the obtained inspection, testing, and analysis measurements must ensure that the SFP's 5 percent subcriticality margin is maintained. Therefore, the acceptance criteria are as follows: o The Boral® panels' boron-10 areal density must remain greater than or equal to 0.028 grams/cm^2. o The Boral® panels' dimensions must remain within the manufacturer's recommended tolerances.

Element Affected	Enhancement
7. Corrective Actions	Update the Metamic® insert surveillance procedure to state that corrective actions are initiated if the results from measurements and analysis indicate that the 5 percent subcriticality margin cannot be maintained because of current or projected future degradation of the neutron-absorbing material. When required, to maintain the subcriticality margin, possible corrective actions consist of providing additional neutron-absorbing capacity with an alternate material or applying other options which are available. State in the AMP's new Boral® panel surveillance procedure that corrective actions are initiated if the results from measurements and analysis indicate that the 5 percent subcriticality margin cannot be maintained because of current or projected future degradation of the neutron-absorbing material. When required, to maintain the subcriticality margin, the possible corrective actions consist of providing additional neutron-absorbing capacity with an alternate material or applying other options which are available.

Operating Experience

Industry Operating Experience

The first U.S. installation of Metamic® occurred in 2007. In the period since, there has been no significant age-related OE for the Metamic® absorber material in the industry. Even though no significant age-related degradation is anticipated for the material, this aging management program performs regular inspections to be able to identify potential aging effects. Industry OE is reviewed periodically to identify any potentially relevant age-related events for Metamic® or Boral®.

Plant Specific Operating Experience

Metamic® inserts were installed in PSL Units 1 and 2 as part of the extended power uprates. The current surveillance requirements have been in place since their installation.

- In 2016 the scheduled four-year inspections were performed on both units. No evidence of degradation was found in these inspections.

- In 2020 the scheduled eight-year inspections were performed on both units. No evidence of degradation was found in these inspections.

- Two ARs were issued (6/8/2017 and 8/29/2018) to document the misplacement of Metamic® inserts. These ARs initiated procedure changes to add instructions for preparation and review of fuel or component moves in the spent fuel pool around the Metamic® Coupon Tree to ensure compliance with the Metamic® Insert Surveillance procedure. This demonstrates an effective use of the corrective action program to document events and develop a programmatic response to preclude future incidents.

Program Assessments and Evaluations

The NRC conducted a license renewal post approval site inspection review which addressed the Metamic® Insert Surveillance Program basis document and implementing procedure. The inspectors verified the program was developed as described in the UFSAR and that the first scheduled surveillance was consistent with the program description.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and the only finding related to the PSL Monitoring of Neutron Absorbing Materials Other Than Boraflex AMP was an administrative issue where the preventive maintenance activities for Metamic® inspections were not flagged with the License Renewal attribute, which has since been corrected.

The PSL Monitoring of Neutron-Absorbing Materials Other Than Boraflex 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 PSL Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP, with enhancements, will provides 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.2.3.27 Buried and Underground Piping and Tanks

Program Description

The PSL Buried and Underground Piping and Tanks AMP is a new condition monitoring AMP that manages the aging effects associated with the external surfaces of buried and underground piping such as loss of material and cracking. It addresses piping composed of steel (carbon steel, cast iron, and ductile iron) and SS materials that are within the scope of Subsequent License Renewal. There are no buried or underground tanks at PSL.

There are no polymeric, cementitious, or additional metallic materials other than the steel metals stated above for the in-scope systems, therefore, the aging management of these materials is not applicable. The interior surfaces of the coated, cement lined cast iron fire water system piping is managed by the PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.3.28) AMP.

The objective of this program is accomplished through the use of preventive, mitigative, inspection, and in some cases, performance monitoring activities. The PSL 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 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 PSL 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 wall thicknesses, and visual inspections of the pipe from the exterior.

PSL currently does not have an active cathodic protection system for buried and underground piping. Backfill specifications, average pH of soil samples, the use of guard pipe and coatings was previous justification for not having a need for an active cathodic protection system for buried steel piping. In accordance with the recommendations of NUREG-2191 AMP XI.M41, a cathodic protection system will be installed 10 years prior to SPEO.

The table below provides additional information related to inspections. Preventive Action Category F has been selected for monitoring steel piping during the initial monitoring period since the cathodic protection system will not be operational during that time period. Upon entering the SPEO, Preventive Action Category C has been selected for buried steel piping after the cathodic protection system has been in service for approximately 10 years and annual effectiveness reviews are performed. However, if these conditions were to change, the Preventive Action Category would require reevaluation and could potentially change.

The number of inspections for each 10-year inspection period, commencing 10 years prior to the start of SPEO, are based on the inspection quantities noted in NUREG-2191, Table XI.M41-2, adjusted for a 2-Unit plant site.

Material	No. of Inspections	Notes
Steel (buried)	11* prior to the SPEO (Category F) 4 in each 10-year period in the SPEO (Category C)	Includes 2 additional inspections to meet the requirements of NUREG-2191 Section XI.M41, paragraph 4.e.i regarding the aging effects associated with fire mains.
Steel (underground)	3	
Stainless steel (buried)	2	

*If after five years of operation the cathodic protection system does not meet the effectiveness acceptance criteria defined by NUREG-2191, Tables XI.M41-2 and -3 (-850 mV relative to a CSE, instant off, for at least 80 percent of the time, and in operation for at least 85 percent of the time), FPL commits to performing two additional buried steel piping inspections beyond the number required by Preventive Action Category F resulting in a total of thirteen (13) inspections being completed six months prior to the SPEO.

This AMP does not provide aging management of selective leaching. The PSL Selective Leaching of Materials (Section B.2.3.21) AMP is applied in addition to this program for applicable materials and environments.

The PSL Buried and Underground Piping and Tanks AMP requires the creation of new governing and inspection procedures consistent with NUREG-2191, Section XI.M41, as well as a new sampling plan and work orders to support the new inspections. A new cathodic protection system will also be installed, and an effectiveness review per Table XI.M41-2 of NUREG-2191, Section XI.M41 will be performed throughout each of the 10-year inspection periods. This AMP is implemented, and the initial inspections begin no earlier than 10 years prior to the SPEO and are completed no later than six months prior to entering the SPEO or no later than the last RFO prior to the SPEO.

NUREG-2191 Consistency

The PSL Buried and Underground Piping and Tanks AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M41, “Buried and Underground Piping and Tanks.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

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 (Reference ML093160004).

- 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 (Reference ML093160004).

- 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 (Reference ML103000405).

- 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 (Reference ML13329A422).

Plant Specific Operating Experience

The PSL Asset Management Plan for the Underground Piping and Tanks Integrity Program covers all relevant OE for the PSL NEI 09-14 program. Relevant inspection OE is presented here:

- The underground carbon steel Auxiliary Feedwater (AFW) piping in trenches was inspected in 2013 and 2014. Based on the inspection findings, the coatings provided good protection to the carbon steel AFW piping in the trenches as evidence by only one required immediate repair. An inspection frequency of ~ 15 years was recommended for periodic inspection of the AFW piping and supports in the trenches since they are exposed to rainwater.

  Inspections performed in Fall 2019 identified piping below minimum wall in a localized area. Because of the corrosion, the reinspection frequency was updated from ~ 15 years to 6 years for both units. Preventive maintenance (PM) activities for both Units were created and captured in the future inspection plan. The Condensate Storage Tank and AFW underground piping trenches make up the majority of underground steel piping trenches at PSL.

  Inspections, including wall thickness measurements, are being monitored and trended in these trenches; frequency of these PMs will be adjusted as any other mitigative measures, including draining capabilities and coating repairs/replacements, are implemented.

- Intake Cooling Water (ICW) supply and discharge buried carbon steel piping was visually inspected in 2011 and 2012 as part of the NEI 09-14 buried piping program: Based on the excellent inspection results and engineering judgment, the ICW supply header piping, discharge header piping, and coatings on both Units are expected to last well beyond the current licensed 60-year plant life. Similar inspections will be performed within the 10-year period prior to the SPEO to determine if additional aging degradation has occurred and perform corrective action as needed to provide reasonable assurance that aging of this piping is managed throughout the plant's 80-year life.

  Visual inspections (internal crawl through) for NRC GL 89-13 which are performed under the current Intake Cooling Water AMP identified thru-wall degradation and pitted areas. Additional dive inspections identified thru-wall holes in areas where previous internal epoxy repairs had been performed. The failure mechanism was internally driven. A root-cause analysis determined the failure was due to the damaged cement liner and failed internal coating that exceeded service life, and dive inspections did not detect internal epoxy patch degradation. Piping replacement and repairs were completed to restore full qualification.

  For SLR, the current activities performed under the Intake Cooling Water AMP will be implemented through the PSL Open Cycle Cooling Water and Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.3.28) AMPs for future inspections. This

AMP is expected to be robust based on numerous corrective actions defined in the root cause evaluation. Currently, new PMs for both Units are on a every six refueling outage frequency to dewater and inspect these discharge lines. These PMs are included in the future inspection plan for in-scope piping for tracking purposes.

- Unit 2 buried diesel fuel oil piping was pressure tested during the Spring 2020 outage. Lines were pressurized up to 110-psig with a zero-psi pressure drop.

  During excavations, many soil samples have been obtained and analyzed. In general, the pH at PSL is approximately 9.0 indicating an alkaline soil environment. Resistivity of samples typically range from 1700 to 5000 ohm-cm. Due to the consistency of soil samples, future soil sampling was determined to not be warranted.

Health reports related to buried piping were reviewed between 2015 and 2020. Items noted during this review include:

- The only non-“Green” quarters were the fourth quarter of 2019 and the first quarter of 2020 which were White. This was based on a reorganization resulting in new program engineer assignments (owner proficiency), more than 5 outstanding changes to the program document, and one piping inspection with results that were below minimum wall thickness. The pipe was repaired promptly in November 2019.

- All other quarters were in a “Green” category.

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 PSL Buried and Underground Piping and Tanks 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 PSL Buried and Underground Piping and Tanks 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.2.3.28 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

Program Description

The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP that will have the principal objective to manage the aging effect of loss of coating/lining integrity.

The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be a condition monitoring AMP that will manage degradation of internal coatings/linings exposed to closed cycle cooling water, raw water, treated water, fuel oil, and air 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 PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will not be used to manage loss of coating integrity for external coatings. The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP performs inspections of coatings/linings applied to components which will be managed by the PSL Outdoor and Large Atmospheric Metallic Storage Tanks AMP (Section B.2.3.17), the PSL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP (Section B.2.3.24), the PSL Open-Cycle Cooling Water AMP (Section B.2.3.11), the PSL Closed Treated Water Systems AMP (Section B.2.3.12), the PSL Fuel Oil Chemistry AMP (Section B.2.3.18) and the PSL Fire Water System AMP (Section B.2.3.16).

The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will manage 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 a 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 will be performed, where physically possible, in conjunction with the visual inspection. The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will use 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 1.6.44) 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 will be inspected. Piping inspections will be sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings will be 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 will not be acceptable. Blisters will be evaluated by a coatings specialist to confirm the surrounding material is sound and the blister size and frequency is not increasing. Minor cracks in cementitious coatings will be acceptable provided there is no evidence of debonding. All other degraded conditions will be evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing will be performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining. Additional inspections will be 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.

While the air, fuel oil, and treated water environments between the two Units meet the criteria listed in GALL-SLR Chapter XI.M42, the components that are coated and exposed to these environments are tanks. As such, the population sizes are too small to reduce the number of inspections required. Because the fire water and service water systems for both Units are supplied from the same raw water source (city water) and the intake cooling water and emergency cooling canal systems for both Units are supplied by the same raw water source (intake canal water), the coatings inspections for each environment (i.e., city water and intake canal water) could be reduced for the two units.

Opportunistic inspections, in lieu of periodic inspections, will be performed for the buried concrete lined fire protection piping. PSL will perform flow tests and internal piping inspections at intervals specified by NUREG-2191, Table XI.M27-1, and will be capable of detecting through-wall flaws in the piping through continuous system pressure monitoring (alarm setpoints). In addition, PSL does not have plant-specific OE regarding buried fire main leaks due to age-related degradation in the coated/lined portions of the piping.

The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will have new governing and inspection procedures 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 PSL 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 baseline inspections will start no earlier than 10 years prior to the SPEO.

NUREG-2191 Consistency

The PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be consistent without exception to the 10 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-2021-02-Mechanical, “Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions. 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 OE pertaining to loss of coating or lining integrity for coatings/linings installed on the internal surfaces of piping systems:

- In 1982, a licensee experienced degradation of internal coatings in its spray pond piping system. This issue contains many key aspects related to coating degradation. These include installation details such as improper curing time, restricted availability of air flow leading to improper curing, installation layers that were too thick, and improper surface preparation (e.g., oils on surface, surface too smooth). The aging mechanisms included severe blistering, moisture entrapment between layers of the coating, delamination, peeling, and widespread rusting. The failure to install the coatings to manufacturer recommendations resulted in flow restrictions to the ultimate heat sink and blockage of an emergency diesel generator governor oil cooler. (Information

Notice 85-24, "Failures of Protective Coatings in Pipes and Heat Exchangers.")

- During a 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. [Agencywide Documents Access and Management System (ADAMS) Accession No. 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 PSL 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.

<u>Plant Specific Operating Experience</u>

The following summary of site-specific OE (which includes review of corrective actions and NRC inspections) provides examples of how PSL is managing aging effects associated with the PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP.

- In August 2011, the U2 PWST interior was inspected. No degradation issues were identified within the normally wetted interior of U2 PWST, however, the inspection of the non-wetted area between the floating roof seal and the tank top identified several minor areas (approximately eight) of corrosion within previous Belzona repaired areas. These areas were approximately ½ inch in diameter and in all cases the carbon steel substrate was corroding. The minor corrosion identified did not affect the ability of the tank to perform its design function; therefore, no corrective action was required. A follow up tank inspection is scheduled for the refueling outage in Spring 2023.
- In March 2018, during a Unit 1 Refueling Water Tank internal floor lining remote inspection, three areas with 6-inch stress cracks were discovered on the fiberglass-reinforced vinyl ester epoxy lining material (Dudick Protecto-Line 800). An evaluation was performed as part of the AR and as a corrective measure, a follow up inspection was scheduled for the next outage. Repairs were performed under a work order.
- The City Water Storage Tank 1A tank internals were visually inspected and ultrasonic testing of the tank bottom was performed under the License Renewal FP Program in October 2020. In general, ultrasonic testing results showed tank floor thickness within nominal thickness -10 percent. Internal coatings had failed in some locations in the tank floor resulting in several locations of localized pitting. Some of these locations were below the minimum wall thickness for the tank floor. There were also other tank components that were corroded due to localized coatings failures. Using engineering judgement, none of the corroded areas or floor pitting below minimum wall thickness impacted tank structural integrity or functionality. Internal City Water Storage Tank recoating is scheduled to be implemented in 2022 as part of the City Water Storage Tank Repair Capital Project.
- The City Water Storage Tank 1B tank internals were visually inspected and ultrasonic testing of the tank bottom was performed under the License Renewal FP Program in October 2020. In general, ultrasonic testing results showed tank floor thickness within nominal thickness -10 percent. Internal coatings had failed in some locations in the tank floor, which resulted in a few locations of localized pitting. Some of these locations were below the minimum wall thickness for the tank floor. There were also other tank components that were corroded due to localized coatings failures. By engineering judgement, none of the corroded areas or floor pitting below

minimum wall thickness impacted tank structural integrity or functionality. Internal City Water Storage Tank recoating is scheduled to be implemented in 2022 as part of the City Water Storage Tank Repair Capital Project.

- The 1A component cooling water heat exchanger end-of-cycle tube cleaning and eddy current test PM identified that there were 30 partially blocked tubes. The tubes were partially blocked with small anode pieces and shells. No significant coating degradation was noted. The OE documents the acceptability of the inspected internal coatings only and is included to demonstrate positive OE for internal coatings. No corrective actions / maintenance was necessary for internal coatings.
- The 2B component cooling water heat exchanger was inspected when the channel heads were removed for preventive maintenance. One small piece of delaminated coating was found during tube inspections. The door and channel head bolt-interface had degraded coatings and required cleaning and refurbishment to prevent loss of material. The coating condition on the area was satisfactory. A work order package repaired the internal coatings.
- A portion of carbon steel and cement lined intake cooling water discharge header piping was inspected. The inspections identified superficial and hairline cracks on the cement lining at three locations. The pipe metal was not exposed in any of these locations. Neither corrosion products nor degradation of the internal pipe metal surface was observed. Based on the above, the decision was made to continue monitoring the cement lining condition in accordance with the pipe inspection PM. This OE documents the acceptability of the inspected internal coatings only and is included to demonstrate positive OE for internal coatings. No corrective actions / maintenance were necessary for the internal coatings.
- Work was performed to refurbish the internal and external surfaces of the intake cooling water pump discharge elbows directly downstream of a check valve. The elbow fitting was removed from the header, had coatings and lining removed, and a new coating system applied.
- The 1A component cooling water heat exchanger channel head flange joint had an active saltwater leak. This joint has had a previous history of leakage since the 1990s. The most likely cause of leakage was attributed to breakdown of internal epoxy coatings inside the channel head. Previous refurbishment of internal coatings yielded the most success. The recommended actions were to remove the coatings to evaluate severity of corrosion, clean the surface, potentially replace some of the fasteners, and re-coat. A one-foot strip of internal coatings in the flange interface zone was removed and the internal channel was refurbished. The flange internal surfaces were then recoated to resolve the issue.
- The 1B component cooling water heat exchanger inlet and outlet channel head areas were inspected. Small pieces of delaminated coatings were found on the tubesheet. The general state of the channel head, tubesheet, cover and tube plugs was satisfactory. No structural/ material damage was identified internally or externally, except for a small area of delaminated coatings inside the inlet piping. An engineering evaluation determined that no corrective measures were required.

- Debris (paint chips/tank sludge) was observed at the bottom of the Unit 1 head tank associated with the instrument air compressor emergency cooling system. The inside of the head tank was cleaned and an evaluation was performed to determine if cleaning was needed on the Unit 2 tank. An engineering change has been written to replace the head tank with a SS tank without internal coatings and has been scheduled in a work order.

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 PSL Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks 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 PSL 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 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 PSL ASME Section XI, Subsection IWE AMP is an existing AMP that was formerly part of the ASME Section XI, Subsection IWE Inservice Inspection program. 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 AMP 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, if required, in accordance with 10 CFR 50.55a prior to implementation.

This AMP includes periodic visual, surface, and volumetric examinations, where applicable, for signs of degradation, damage, irregularities, and for coated areas distress of the underlying metal shell, and corrective actions. Acceptability of inaccessible areas of steel containment vessel 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, metal shell locations susceptible to corrosion that are inaccessible from one side. Guidance provided in EPRI TR-107514 will be considered for sampling determinations. The trigger for this one-time examination is site-specific occurrence or recurrence of metal shell corrosion (base metal material loss exceeding 10 percent of nominal plate thickness) that is determined to originate from the inaccessible side. Any such instance would be identified through code inspections performed since 10/02/2003. Based on a review of current PSL OE, no such triggers have occurred.

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 PSL Protective Coating Monitoring and Maintenance AMP (Section B.2.3.35) is used for the monitoring and maintenance of protective containment coatings in relation to reasonable assurance of emergency core cooling system operability.

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, 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. Internal and external moisture barriers are examined for wear, damage, erosion, tear, surface cracks, and other defects, which may violate their leak tight integrity.

Cumulative fatigue damage for the PSL containment vessels and piping penetrations (including ventilation and fuel transfer 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 all non-piping penetrations (equipment hatch, personnel locks, electrical penetrations, etc.) that are subject to cyclic loading but have no current licensing bases fatigue analysis will be managed by the 10 CFR Part 50, Appendix J AMP (Section B.2.3.31) or by periodic supplemental surface or enhanced visual examinations incorporated into and consistent with the frequency of this AMP. This AMP will also include supplemental one-time inspections within 5 years prior to the SPEO for a representative sample of SS penetrations and dissimilar metal welds, including the fuel transfer tubes, that may be susceptible 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-3000 or accepted by engineering evaluation.

NUREG-2191 Consistency

The PSL ASME Section XI, Subsection IWE AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.S1, “ASME Section XI, Subsection IWE.”

Exceptions to NUREG-2191

None.

Enhancements

The PSL ASME Section XI, Subsection IWE AMP will be enhanced as follows, for alignment with NUREG-2191. The one-time inspections for cracking due to SCC will be started no earlier than five years prior to the SPEO. The enhancements are to be implemented and one-time inspections completed no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Procedures will be revised 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” and EPRI TR-104213, “Bolted Joint Maintenance & Application Guide.”
2. Preventive Actions	Procedures will be revised to specify that for structural bolting consisting of ASTM A325, ASTM A490, and equivalent materials, 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.

Element Affected	Enhancement
4. Detection of Aging Effects	Procedures will be revised to perform periodic supplemental surface or enhanced visual examinations at intervals no greater than 10 years to detect cracking due to cyclic loading of all non-piping penetrations (hatches, electrical penetrations, etc.) that are subject to cyclic loading but have no current licensing bases fatigue analysis and are not subject to local leak rate testing.
4. Detection of Aging Effects	Procedures will be revised to implement supplemental one-time surface or enhanced visual examinations, performed by qualified personnel using methods capable of detecting cracking, comprising (a) a representative sample (two) of the SS penetrations or dissimilar metal welds associated with high-temperature (temperatures above 140°F) SS piping systems in frequent use on each unit; and (b) the SS fuel transfer tube on each unit. These inspections are intended to confirm the absence of SCC aging effects.
4. Detection of Aging Effects	Procedures will be revised to specify a one-time volumetric examination of metal shell surfaces that are inaccessible from one side if triggered by plant-specific OE identified after the date of issuance of the first renewed license for each unit. If triggered, this inspection will be performed by sampling randomly selected, as well as focused, metal shell locations susceptible to corrosion that are inaccessible from one side. The trigger for this one-time examination is site-specific occurrence or recurrence of metal shell corrosion (base metal material loss exceeding 10% of nominal plate thickness) that is determined to originate from the inaccessible side. Any such instance would be identified through code inspections performed since 10/02/2003. Guidance provided in EPRI TR-107514 will be considered when establishing a sampling plan. This sampling is conducted to demonstrate, with 95% confidence, that 95% of the accessible portion of the metal shell is not experiencing greater than 10% wall loss.
7. Corrective Actions	If SCC is identified as a result of the supplemental one-time inspections, additional inspections will be conducted in accordance with the site's corrective action process. This will include one additional penetration with dissimilar metal welds associated with greater than 140°F SS piping systems for each Unit until cracking is no longer detected. Periodic inspection of subject penetrations with dissimilar metal welds for cracking will be added to the PSL ASME Section XI, Subsection IWE AMP if necessary, depending on the inspection results.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

- On May 5th, 2014, the NRC issued IN 2014-07, "Degradation of Leak Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner." The contents of IN 2014-07 were reviewed in an AR by the PSL Containment ISI Program Owner. PSL does not have leak-chase channels as described in the IN. A temporary leak-chase channel was installed during the 1997 refueling outage to facilitate testing on the Unit 1 Construction Hatch but was removed in the same outage. Grout channels were used during construction for the concrete base mat fill upon initial settling of the containment vessel; however, these channels were filled in during completion of the construction process. Thus, the review concluded that IN 2014-07 does not have applicability to the PSL containment design and construction.

Plant Specific Operating Experience

- Owner's Activity Reports (OARs) from 2004 to 2020 were reviewed. There were no flaws identified nor any other significant issues applicable to IWE reported during this time period.

- Plant specific OE prior to the Period of Extended Operation (PEO) showed that loss of seal occurred with non-metallic components such as gaskets and seals. In each case, these components were replaced in accordance with approved plant procedures. Similar items continue to be detected during IWE examinations, but no on-going degradation mechanisms have been identified that would question the integrity of containment.

    - During the scheduled IWE examinations of the Unit 1 containment (annulus side) in March 2018, two locations were identified where failure to install softeners allowed a scaffold to contact the containment vessel. No chipped paint was found at the contact points and the scaffold installation was immediately corrected (i.e., softeners installed on the day of the finding). Procedural requirements for building scaffold near or up against the containment vessel were reviewed with all carpenters and carpenter helpers.

    - During the ASME Section XI IWE general visual examinations of the Unit 1 vessel surface (annulus side and inside containment) in October 2019, various areas of chipped paint and gouges were observed. After review of the reported conditions and associated photographs, an engineering evaluation determined that the chipped and gouged coatings were damaged by material handling and that observed conditions were not the result of coating defect or other deterioration. Inside the containment, the steel vessel remained coated with primer in those locations that exhibited only chipped top coatings. With the exception of one small spot of surface rust on the annulus side, no corrosion was present in those locations gouged/ground down to bare metal (a total affected area of well under one square foot). Because the effect of corrosion propagated over the span of one fuel cycle was considered insignificant when compared to the robust nature of the containment vessel, the noted damage was determined to have negligible impact to the structural integrity of the steel containment vessel. The conditions inside containment were documented in a closeout inspection report. Repair in accordance with the applicable coating specifications was deferred to the next outage.

- During scheduled IWE examinations of the Unit 1 containment in October 2019, cotter pins were noted missing on two of the containment maintenance hatch bolts. The associated load pins were found to be loaded and functioning per design. Before the end of the outage, the unsatisfactory conditions were corrected at both locations.

- The scheduled ASME Section XI IWE examination of the Unit 2 containment (annulus side) in February 2020 identified 16 indications of moisture barrier degradation (lack of adhesion at the concrete interface or at the containment vessel). Considering the dry conditions in the annulus, engineering evaluation deemed all degraded conditions to be minimal with negligible impact to structural integrity of the containment vessel. Before the end of the outage, the moisture barrier seal (annulus and containment side) was repaired in accordance with the applicable coating specification.

All instances of corrosion in the above examples originated on the accessible surfaces of the containment vessel. In each case of recordable indications on containment moisture barriers, the moisture barrier was repaired. Corrosion, if it existed, was sufficiently superficial that component function would not be impacted. The above examples demonstrate that the inspections executed under the PSL 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.

- ISI program health reports were reviewed for the last five years (2015 through 2020). For most of that window, the overall program status was Acceptable (Green) with one clarification. In the third and fourth quarters of 2018, the following items contributed to a White status for the ISI program: (1) assignment of a new fully qualified AMP owner with less than three years' experience; (2) deferral of 12 scheduled examinations to a subsequent outage due to inadequate preparations; and (3) in-core instrumentation leakage identified during head visual examinations (attributed to poor disassembly practices) requiring re-examination during a subsequent outage. Overall program status returned to Green in the first quarter of 2019 following completion of examinations during the refueling outage and has remained Green throughout the remainder of the review timeframe.

<u>Program Assessments and Evaluations</u>

- NRC Post-Approval site Inspections described in License Renewal Phase 2 Inspection Reports for Units 1 and 2 were reviewed regarding the PSL ASME Section XI, Subsection IWE AMP. The inspectors reviewed the program basis document, the IWE ISI program plan, recent program health reports, and a sample of implementing procedures. The inspectors also reviewed a sample of ISI summary reports. The inspectors verified that the program was implemented in accordance with the licensing basis and that inspections were performed in accordance with ASME Section XI requirements. In response to an observation by the inspectors, PSL added text to the program basis document clarifying that the XI.S8 AMP described in GALL, Revision 2, was not implemented during the PEO. Since the comparable GALL-SLR AMP (Section B.2.3.35) will be implemented for SLR, the clarification is not maintained in this document.

- On December 31st, 2016, the NRC completed an inspection of PSL Units 1 and 2. The resulting integrated inspection report was reviewed regarding the PSL ASME Section XI, Subsection IWE AMP. While conducting a review of ISI program implementation in October 2016, the inspectors independently walked down the moisture barrier seal between the Unit 1 containment inner shell plate and floor at elevation 18' for signs of degradation and reviewed the associated evaluation for compliance with paragraph IWE-3510 of Section XI of the ASME 2001 Boiler and Pressure Vessel Code. No findings were identified.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL ASME Section XI, Subsection IWE AMP were identified.

The PSL 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 PSL ASME Section XI, Subsection IWE 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.2.3.30 ASME Section XI, Subsection IWF

Program Description

The PSL 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. This AMP is also credited for identifying visible indications of loss of fracture toughness due to irradiation embrittlement of the reactor vessel 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 AMP 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 evaluated from an aging management point of view in accordance with 10 CFR 50.59 and reviewed/ approved by the NRC staff under 10 CFR 50.55a, if required, before they are implemented.

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, for Class 1, 2, and 3 piping and component supports. The primary inspection method employed is visual examination. Non-destructive 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 preventive actions for storage 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.

NUREG-2191 Consistency

The PSL ASME Section XI, Subsection IWF AMP, with enhancements, will be consistent with exceptions to the 10 elements of NUREG-2191, Section XI.S3, “ASME Section XI, Subsection IWF”.

Exceptions to NUREG-2191

The PSL ASME Section XI, Subsection IWF AMP includes the following exceptions to the NUREG-2191 guidance:

1. Inspection of supports for Class MC components under ASME Section XI, Subsection IWF is not required by 10 CFR 50.55a and PSL does not include such inspections in its IWF ISI program. (Note: There are no Class MC component supports at PSL.) 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 vessel and its integral attachments, including penetrations and fuel transfer tube components, is included in the scope of the PSL ASME Section XI, Subsection IWE (Section B.2.3.29) AMP. Structural supports other than ASME Class 1, 2, and 3 supports and in other areas of the plant outside containment are inspected under the PSL Structures Monitoring (Section B.2.3.33) AMP. Therefore, PSL meets the intent of this NUREG-2191 program element.

2. Site documentation indicates that high-strength bolts (including bolts conforming to ASTM A490, "Standard Specification for Structural Bolts, Alloy Steel, Heat Treated, 150 ksi Minimum Tensile Strength") are acceptable for use in structural applications at PSL. This is an exception to the AMP described in Section XI.S3 of NUREG-2191, which recommends using bolting material for structural applications that have an actual measured yield strength limited to less than 1,034 megapascals (MPa)(150 kilo-pounds per square inch) as a preventive measure that can reduce the potential for SSC. Although current specifications allow for the use of A490 high-strength bolting, the original construction specifications required the use of ASTM A325 bolting. Structural field connections were specified to be friction type joints, assembled with 7/8-inch diameter high-strength bolts, unless otherwise noted on drawings. PSL performs visual inspection of high-strength bolting in accordance with ASTM A325 and ASTM A490. As discussed above, PSL prohibits the use of MoS_2 and other sulfur containing lubricants as a preventive measure to reduce SCC of high-strength bolting. The other preventive actions (use of appropriate lubricants, appropriate installation torque, and appropriate storage) in NUREG-2191 XI.S3 AMP that can reduce the potential cracking are implemented by the PSL ASME Section XI, Subsection IWF AMP. This AMP includes enhancements for identification of high-strength structural bolting and for additional actions to provide reasonable assurance that SCC is not occurring. The exception is acceptable because PSL meets all other program element requirements for structural bolting.

Enhancements

The PSL 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	Identify the population of ASME Class 1, 2, and 3 high-strength structural bolting greater than one-inch nominal diameter within the boundaries of IWF-1300.
1. Scope of Program	Procedures will be revised to evaluate the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions are identified in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.
2. Preventive Actions	Procedures will be revised to specify the use of high-strength bolt storage requirements discussed in Section 2 of RCSC (Research Council for Structural Connections) publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts," for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts.
3. Parameters Monitored or Inspected	Procedures will be revised 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	Procedures will be revised to specify that accessible sliding surfaces are monitored for significant loss of material due to wear and accumulation of debris or dirt.
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. The one-time inspection will occur within five years prior to entering the SPEO.
4. Detection of Aging Effects	Procedures will be revised to specify that, for component supports with 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. A representative sample of bolts will be inspected during the inspection interval prior to the start of the SPEO and in each 10-year period during the SPEO. The sample will be 20% of the population (for a material / environment combination) up to a maximum of 25 bolts.
5. Monitoring and Trending	Procedures will be revised to increase or modify the component support inspection population when a component support is repaired to as-new condition by including another support that is representative of the remaining population of supports that were not repaired.

Element Affected	Enhancement
6. Acceptance Criteria	Procedures will be revised 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; and • Cracked or sheared bolts, including high-strength bolts, and anchors.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

- Industry OE described an event where RV supports were not included in the ISI Program, and IWF exams were not being performed. This OE was evaluated and found to be applicable to PSL. The review of this OE determined that (a) the Unit 2 RV supports were not being examined and (b) supports for the Unit 1 Component Cooling Water (CCW) heat exchangers and pumps had not been included in the program. Examinations of the Unit 1 CCW heat exchanger and pump supports were successfully completed in January 2012. Examinations of the PSL RV supports were performed in the 2013 Fall Outage for Unit 1 and in the 2012 Fall Outage for Unit 2; no items requiring repair/replacement or evaluation were identified. Examinations for all component supports identified as missing were added to the ISI database to ensure they would be examined in future intervals.

- Industry OE described an 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 evaluated for PSL. Neither PSL Unit 1 nor Unit 2 has a shroud seismic support assembly as described in the OE report; rather, the shroud itself in both Units is free-standing and anchored to the reactor head. Although the shroud provides support to an RV vent line, ASME Section XI exempts that piping from examination and repair/replacement requirements (per IWB-1220 and IWA-7000, respectively); the associated supports are also exempt (per IWF-1230 and IWA-7000, respectively). Thus, the review concluded that this OE does not have applicability to the PSL ISI program.

These examples provide objective evidence that industry OE is being reviewed and evaluated to confirm that station testing procedures are effective to manage aging effects for ASME component supports.

Plant Specific Operating Experience

- Owners Activity Reports (OARs) were reviewed over the last eight years (2012-2020). There were no flaws identified nor any other significant issues reported during this time period.

- The ASME Section XI, Subsection IWF examinations of the Class 1, 2, and 3 component supports have been conducted since plant initial start-up as part of the PSL ISI program commitments and as required by the plant Technical Specifications. General corrosion conditions were identified that resulted in the replacement of variable springs, pipe clamps, and structural members (primarily for supports that are exposed to the humid, salt-laden outdoor environment). These examinations have been successful in identifying degraded conditions associated with component supports within the PSL ISI program scope.

- ISI program health reports were reviewed for the last five years (2015 through 2020). For most of that window, the overall program status was Acceptable (Green) with one clarification. In the third and fourth quarters of 2018, the following items contributed to a White status for the ISI program: (1) assignment of a new fully qualified AMP owner with less than three years' experience; (2) deferral of 12 scheduled examinations to a subsequent outage due to inadequate preparations; and (3) in-core instrumentation leakage identified during head visual examinations (attributed to poor disassembly practices) requiring re-examination during a subsequent outage. Overall program status returned to Green in the first quarter of 2019 following completion of examinations during the refueling outage and has remained Green throughout the remainder of the review timeframe.

Program Assessments and Evaluations

- A focused self-assessment was initiated in November 2010 to determine whether PSL license renewal commitments had been completed, were being tracked, and were being maintained up to date including consideration for EPU design changes. A Nuclear Oversight evaluator (conducting a parallel audit in February 2011) identified that self-assessments focusing on AMPs had not been performed as required by fleet procedure and that AMP owner position responsibilities had not been assigned. The focused self-assessment report was completed in July 2011. Along with the need to assign program owners and schedule periodic self-assessments for AMPs that had not yet been reviewed, the report identified various additional areas for improvement. Corrective actions to resolve all reported items were completed as part of license renewal implementation. None had an impact to the ASME Section XI, Subsection IWF AMP.

- A focused self-assessment was conducted in February 2015 to evaluate the readiness of the PSL Unit 1 license renewal implementation project for impending NRC post-approval inspections. The review included verification of 10 CFR 50.59 screenings for AMP basis documents, an evaluation of Unit 1 changes against the requirements of 10 CFR 54.37(b), and documentation of training for AMP owners. While several general enhancements applicable to all AMPs were identified in the report completed in September 2015, none of the specific inspection notebook recommendations impacted the ASME Section XI, Subsection IWF AMP.

- A focused self-assessment was initiated in January 2017 to evaluate the readiness of the PSL Unit 2 license renewal implementation project for impending NRC post-approval inspections. The review included an evaluation of Unit 2 changes against the requirements of 10 CFR 54.37(b) and confirmation of inter-relationships between AMPs. While several general enhancements applicable to all AMPs were identified in the report completed in April 2017, none of the specific inspection notebook recommendations impacted the ASME Section XI, Subsection IWF AMP.

- NRC Post-Approval site Inspections described in License Renewal Phase 2 Inspection Reports for Units 1 and 2 were reviewed regarding the PSL ASME Section XI, Subsection IWF AMP. The inspectors reviewed the program basis document, the IWE ISI program plan, recent program health reports, and a sample of implementing procedures. The inspectors also reviewed a sample of ISI summary reports. The inspectors verified that the program was implemented in accordance with the licensing basis and that inspections were performed in accordance with ASME Section XI requirements.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL ASME Section XI, Subsection IWF AMP were identified.

The PSL 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 PSL ASME Section XI, Subsection IWF AMP, with enhancements and exceptions, 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.2.3.31 10 CFR Part 50, Appendix J

Program Description

The PSL 10 CFR Part 50, Appendix J AMP is an existing AMP that was formerly credited for initial license renewal as part of the ASME Section XI, Subsection IWE Inservice Inspection AMP. The PSL 10 CFR Part 50, Appendix J AMP is a performance monitoring program that monitors the leakage rates through the containment system, its vessel, 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 the acceptance criteria dictated in the PSL Unit 1 and Unit 2 Technical Specifications.

This AMP is implemented in accordance with 10 CFR Part 50, Appendix J, NEI 94-01 Revision 2-A (Reference ML100620847), "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. This AMP credits the existing AMP required by 10 CFR Part 50, Appendix J.

The PSL containment system consists of a containment vessel (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 provide reasonable assurance that (a) leakage through these containments or system and components penetrating these containments does not exceed allowable leakage rates specified in the PSL technical specifications (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. PSL uses the performance-based approach, Option B.

The monitored parameters are leakage rates through the containment vessel, penetrations, associated welds, access openings, and associated pressure boundary components. Three types of tests (Type A, Type B, and Type C) are performed at PSL 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.

For containment pressure boundary components that do not receive scheduled Type B or Type C tests, the following programs also manage applicable aging effects:

- ASME Section XI, Subsection IWE AMP (Section B.2.3.29) for the penetration assemblies
- Boric Acid Corrosion AMP (Section B.2.3.4) for susceptible materials

- External Surfaces Monitoring of Mechanical Components AMP (Section B.2.3.23)
- Closed Treated Water Systems AMP (Section B.2.3.12) for internal surface of pertinent components
- Flow-Accelerated Corrosion AMP (Section B.2.3.8) for the internal surface of susceptible components in high temperature systems
- Water Chemistry AMP (Section B.2.3.2) for internal surface of pertinent components, as verified by the One-Time Inspection AMP (Section B.2.3.20) for internal surface of pertinent components
- Fatigue Monitoring AMP (Section B.2.2.1)

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 PSL 10 CFR Part 50, Appendix J AMP meets this requirement with its visual inspection procedures. Additionally, the PSL 10 CFR Part 50, Appendix J AMP inspections may be performed in conjunction with the PSL AMP associated with ASME Code Section XI, Subsection IWE 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. Furthermore, the combination of Type B Appendix J LLRTs, general visual examinations and ASME Section XI, Subsection IWE AMP (Section B.2.3.29) inspections will be supplemented by surface or enhanced visual examinations of non-piping penetrations (hatches, electrical penetrations etc.) subject to cyclic loading to detect potential cracking.

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 PSL 10 CFR Part 50, Appendix J AMP is consistent without exception to 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

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

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 SS 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. The containment vessel piping penetration bellows that are installed at PSL Units 1 and 2 are predominantly structural type bellows, designed such that the bellows are not subjected to piping operating system parameters (i.e., not part of the process line pressure boundary). PSL plant-specific OE has not identified cracking of these bellows as an aging effect requiring management. Bellows that form a portion of the containment leak tight boundary are leak rate tested in accordance with 10 CFR Part 50, Appendix J.

Plant Specific Operating Experience

The status of the PSL 10 CFR Part 50, Appendix J program is tracked and trended via quarterly program health reports. A review of the quarterly program health reports for 2015 through 2020 determined that the PSL 10 CFR Part 50, Appendix J AMP has been GREEN in 2020 and 2017, WHITE in 2019, 2017, and 2016, and YELLOW in 2018. Prior program health reports identified isolated incidents of components that exceeded the administrative limits. Issues were corrected via the corrective action process prior to the end of the outages, and no repeat failures were found.

The following review of site-specific OE demonstrates how PSL is managing aging effects associated with the PSL 10 CFR Part 50, Appendix J AMP.

- In October 2015, during local leak rate testing (Type B), the leakage rate across the Unit 2 RCB Escape Airlock outer door seal exceeded the TS criteria. It was determined that the leakage was coming from the larger diameter of the two o-ring gaskets or sealing surfaces. The seal was replaced and the door seal was retested with satisfactory results.

  This example demonstrates that the inspections and tests executed under the PSL 10 CFR Part 50, Appendix J AMP and the follow-on use of the CAP are effective in evaluating degradation conditions and implementing activities to maintain component intended function.

- In August 2016, during performance of local leak rate testing (Type B), the Unit 1 escape airlock inner door (containment side) failed. The test was being performed following replacement of the interior door seal as preventive maintenance. The door seal was retested prior to entering Mode 4 and passed. During subsequent LLRT in November 2016, the escape airlock inner door seal again failed. The leakage on the escape airlock outer door was well within the TS allowable leakage rate. A TS Action was generated with a Mode 4 hold to address the inner door seal leakage. The door was replumbed and retested with satisfactory results.

This example demonstrates that the inspections and tests executed under the PSL 10 CFR Part 50, Appendix J AMP and the follow-on use of the CAP are effective in evaluating degradation conditions and implementing activities to maintain component intended function.

- In March 2018, during performance of local leak rate testing (Type C) on Unit 1, the leakage rate past an isolation valve exceeded allowable leakage rates. The issue was entered into the corrective action program and a work request was initiated to prevent the plant from entering Mode 4, in which the valve would be required to be operable. An evaluation determined that a retest was appropriate. The retest confirmed a satisfactory LLRT.

  This example demonstrates that the inspections and tests executed under the PSL 10 CFR Part 50, Appendix J AMP and the follow-on use of the CAP are effective in evaluating degradation conditions and implementing activities to maintain component intended function.

- In February 2020, the leak rate at Unit 2 Electrical Penetration B-1 was reading 5,488 sccm, which is in excess of the admin limit of 5,000 sccm. The condition was required to be corrected or dispositioned as acceptable prior to entering a Mode of operation where the affected SSC is required to be Operable and/or Functional (Mode 4). An evaluation concluded that the worst case leakage value remains less that the UFSAR combined limit of 585,233 sccm, and that further degradation during the cycle will not challenge the combined leakage limit. Electrical Penetration B-1 is currently operable based on this engineering judgement. A work order has been initiated to complete repairs to the penetration feedthrough assemblies during the next scheduled outage.

Program Assessments and Evaluations

On November 20, 2015 and October 20, 2017, the NRC completed a Post-Approval Site Inspection for License Renewal at PSL Unit 1 and Unit 2, respectively, in accordance with NRC IP71003. The NRC inspectors did not identify any findings or violations of more than minor significance and determined that the overall implementation of aging management programs and time-limited aging analyses was consistent with the licensing basis of the facility. The inspectors also determined that the regulatory requirements of 10 CFR 54.37(b) were met, and commitment changes were evaluated and reported in accordance with the applicable requirements.

The Unit 2 inspection report specifically reviewed the ASME Section XI, Subsection IWE (Section B.2.3.29), Inservice Inspection Program, which included the 10 CFR Part 50, Appendix J AMP. The inspectors reviewed the program basis document, the in-service inspection program plan, recent program health reports, and a sample of implementing procedures, to verify that the program was implemented in accordance with the licensing basis. The inspectors also reviewed a sample of in-service inspection summary reports to verify that inspections were performed in accordance with ASME Section XI requirements.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and some findings related to the 10 CFR Part 50, Appendix J AMP were identified. The review determined administrative actions to include Appendix J implementing procedures in the License Renewal Basis Document.

The PSL 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 PSL 10 CFR Part 50, Appendix J AMP provides 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.2.3.32 Masonry Walls

Program Description

The PSL Masonry Walls AMP is an existing AMP that was evaluated as a portion of the PSL Systems and Structures Monitoring AMP in the initial license renewal application. The PSL 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 PSL Masonry Walls AMP is a condition monitoring AMP that consists of inspection of masonry walls to detect loss of material and cracking of masonry units and mortar. The aging effects are detected through monitoring for potential shrinkage and/or separation, cracking of masonry walls, and cracking or loss of material at the mortar joints. The AMP will be enhanced to monitor and inspect for gaps between the supports and masonry walls that could potentially impact the intended function or potentially invalidate its evaluation basis, 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 PSL Fire Protection AMP (Section B.2.3.15).

NUREG-2191 Consistency

The PSL Masonry Walls AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.S5, “Masonry Walls”.

Exceptions to NUREG-2191

None.

Enhancements

The PSL Masonry Walls 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
3. Parameters Monitored or Inspected	Revise the implementing procedure to monitor and inspect for 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 the implementing procedure to include specific monitoring, measurement, and trending of 1) widths and lengths of cracks in masonry walls and mortar joints, and 2) gaps between supports and masonry walls.
6. Acceptance Criteria	Revise the implementing procedure to include specific guidance for the assessment of the acceptability of the widths and lengths of cracks in masonry walls and mortar joints and of gaps between supports and masonry walls, using evaluation bases established in response to IE Bulletin 80-11 to confirm that the degradation has not invalidated the original evaluation assumptions or impacted the capability to perform the intended functions.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

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. 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 subsequent period of extended operation.

Plant Specific Operating Experience

Structural walkdowns are implemented by individual PMRQs, which are organized by area. Results of the walkdowns are documented on monitoring checklist forms. Overall program health is documented in the Structures Monitoring Program Health Reports. The Structures Monitoring Program Health Reports have not identified any issues with masonry walls. The PSL Structures Monitoring AMP (Section B.2.3.33) contains an overview of the program health reports.

The following review of plant-specific OE demonstrates how PSL is managing aging effects associated with the PSL Masonry Walls AMP.

- Cracks and delamination were observed in the supporting structure for a door in the southeast corner of the Unit 1 Trestle. An evaluation determined that the cracks identified were isolated from each other and the degradation was localized. The structural integrity of the wall was not compromised. The degradation was entered into the corrective action program and the necessary repairs were completed.

- Cracks and corroded embedded steel were observed in the interior floor and reinforced concrete and masonry block walls of the Unit 1 reactor auxiliary building. An evaluation determined that the degradation did not impact SR equipment. The degradation was entered into the corrective action program and a work order was initiated to complete the repairs.

- Cracking was identified in the masonry block walls in the Unit 2 turbine building. An evaluation determined that the conditions did not affect the structural components' function, integrity, or ability to withstand a design basis event. The degradation was entered into the corrective action program and a work order was initiated to complete the repairs.

Program Assessments and Evaluations

The PSL Structures Monitoring (Section B.2.3.33) AMP has also been enhanced as a result of OE. Examples of improvements to the Structures Monitoring Program governing procedure are summarized in SLRA Section B.2.3.33.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Masonry Walls AMP were identified.

The PSL 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 PSL Masonry Walls 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.2.3.33 Structures Monitoring

Program Description

The PSL Structures Monitoring AMP is an existing AMP that was previously evaluated as part of the PSL Systems and Structures Monitoring AMP in the initial license renewal application. The PSL Structures Monitoring AMP is a condition monitoring AMP that is based on the requirements of Title 10 of the Code of Federal Regulations (10 CFR) 50.65 (the “Maintenance Rule”), U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.160, and Nuclear Management and Resources Council (NUMARC) 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 PSL Structures Monitoring AMP consists primarily of periodic visual inspections of plant structures and 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. The condition of steel is compared to design standards and evaluated.

Inspections and evaluations are performed by qualified personnel using criteria derived from industry codes and standards contained in the plant CLB, including ACI 349.3R. Inspections and evaluations are performed at no interval greater than 5 years with identified degraded conditions receiving more frequent inspection, as warranted, until repaired. The AMP includes preventive actions to provide reasonable assurance of structural bolting integrity.

The groundwater/soil at PSL is judged to be aggressive (chlorides > 500 ppm). Since the chloride levels for seawater are much greater than 500 ppm, there is reasonable certainty that any groundwater/soil chemistry tests will consistently result in chloride level readings that are greater than 500 ppm, which indicates an aggressive groundwater/soil classification, and periodic sampling and testing of groundwater is not necessary.

Included in the program is: inspection of structures, including SR buildings and the internal structures within containment; inspection of NNS structures; inspection of structural steel elements; inspection of elastomers; and inspection of the component supports commodity group and architectural items.

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. Service Level I coatings in containment are managed by the Protective Coating Monitoring and Maintenance AMP (Section B.2.3.35).

NUREG-2191 Consistency

The PSL Structures Monitoring AMP with enhancements will be consistent with exception to the 10 elements of NUREG-2191, Section XI.S6, "Structures Monitoring."

Exceptions to NUREG-2191

The PSL Structures Monitoring AMP includes the following exception to the NUREG-2191 guidance:

1. The groundwater/soil at PSL is considered aggressive and is expected to be consistently aggressive throughout SPEO due to the plant's proximity to the Atlantic Ocean. Since periodic sampling and testing of the groundwater will not impact the groundwater/soil classification, periodic sampling and testing of the groundwater/soil is unnecessary for the PSL Structures Monitoring AMP.

Enhancements

The PSL Structures Monitoring 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	Update the governing AMP procedure and other applicable procedures to monitor and inspect steel edge supports on masonry walls.
2. Preventive Actions	Update the governing AMP procedure and other applicable procedures to specify the use of high-strength bolt storage requirements discussed in Section 2 of the Research Council for Structural Connections publication, "Specification for Structural Joints Using High-Strength Bolts," for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts.
3. Parameters Monitored or Inspected	Update the governing AMP procedure and other applicable procedures to inspect concrete structures for increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation.
3. Parameters Monitored or Inspected	Update the governing AMP procedure and other applicable procedures to inspect elastomers for loss of material and loss of strength.
3. Parameters Monitored or Inspected	Update the governing AMP procedure and other applicable procedures to inspect SS and aluminum components for pitting and crevice corrosion, and evidence of cracking due to SCC.
3. Parameters Monitored or Inspected	Update the governing AMP procedure and other applicable procedures to include monitoring and trending of leakage volumes and chemistry for signs of concrete or steel reinforcement degradation if active through-wall leakage or groundwater infiltration is identified.

Element Affected	Enhancement
4. Detection of Aging Effects	Update the governing AMP procedure and other applicable procedures to include tactile inspection in addition to visual inspection of elastomeric elements to detect hardening.
4. Detection of Aging Effects	Update the governing AMP procedure and other applicable procedures to include evidence of water in-leakage as a finding requiring further evaluation. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessment may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the water.
4. Detection of Aging Effects	Update the governing AMP procedure and other applicable procedures to address the aggressive groundwater/soil environment to account for the extent of the degradation experienced. Specific requirements include evaluations, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed 5 years.
4. Detection of Aging Effects	Update the governing AMP procedure and other applicable procedures to require inspections of the Condensate Storage Tank (CST) and Auxiliary Feedwater (AFW) Structures and Piping Inspections in the Trenches every third refueling outage, which will ensure that these inspections are performed at least once per 5 years.

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. Licensees who responded to the survey reported cracking, scaling, and leaching of concrete structures. The degradation was attributed to drying shrinkage, freeze-thaw, and abrasion. The NUREG also describes the results of NRC staff inspections at six plants. The staff observed concrete degradation, corrosion of component support members and anchor bolts, cracks and other deterioration of masonry walls, and ground water leakage and seepage into underground structures. Information Notice (IN) 2011-20 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 SR concrete structures. Many license renewal applicants have found it necessary to enhance their Structures Monitoring AMPs to ensure that the aging effects of SCs in the scope of 10 CFR 54.4 are adequately managed during the subsequent period of extended operation.

Plant Specific Operating Experience

The Systems and Structures Monitoring Program OE is described in inspection notebooks compiled in support of the 2015 (Unit 1) and 2017 (Unit 2) NRC post-approval site inspections (Unit 1 Inspection Report 05000335/2015010, Unit 2 Inspection Reports 05000389/2017008 and 05000389/2017009). The NRC inspectors did not identify any findings or violations of more than minor significance during the post-approval site inspections.

The Unit 1 inspection report issued in January 2015 documented the following conclusions:

- The UFSAR cites the License Renewal commitment to 1) manage the aging effects of loss of material, cracking, fouling (for mechanical components only), loss of seal, and change in properties, 2) provide for periodic visual inspection and examination, following strict guidelines and specific acceptance criteria for the inspection attributes, for degradation of accessible surfaces of specific SSCs, 3) corrective actions, as required, based on these inspections, and 4) conditions that exceed the acceptance criteria are entered into the CAP for evaluation.
- The program was enhanced as described in the LRA and the corresponding NRC SER, based on a review of program basis documents, administrative and implementing procedures, and license renewal drawings.
- The results of the inspections outlined in the commitment were consistent with the licensing basis, based on interviews with PSL personnel to discuss the scope of the program.
- The evaluation of results was performed in accordance with the program's implementing procedures, based on a review of the results of the latest program walkdowns and independent walkdowns of selected SSCs.

The Unit 2 inspection report issued in April 2017 documented the following conclusions:

- The PSL developed procedures and conducted inspections, as described in the Program Basis Document and the UFSAR.
- The inspections were appropriately scheduled and tracked.
- The PSL properly evaluated, reported, and approved, where necessary, changes to license renewal commitments listed in the UFSAR in accordance with 10 CFR 50.59.

The Unit 2 inspection report issued in November 2017 documented the following conclusions:

- The program was enhanced as described in the LRA and the corresponding NRC SER, based on a review of program basis documents, administrative and implementing procedures.
- The results of the inspections outlined in the commitment were consistent with the licensing basis based on interviews with PSL personnel.

- The evaluation of results was performed in accordance with the program's implementing procedures, based on a review of the results of the latest program walkdowns.

PSL Structures Monitoring health reports are developed and trended. Program health reports from 2015 to present indicate that inspections, procedures, and plans meet the program requirements. The overall performance of the PSL Structures Monitoring AMP is WHITE. The path to GREEN involves reducing a backlog of mostly white and some yellow work orders.

The following review of site-specific OE demonstrates how PSL is managing aging effects associated with the PSL Structures Monitoring AMP.

- Corroded pipe support spring cans were observed during a Structures Monitoring Program walkdown for the Unit 2 Refueling Water Tank. Corrosion had been identified on the two spring supports, as documented in previous ARs. The evaluation noted that no additional degradation had occurred, and the spring cans were replaced.
- Observations during Structures Monitoring walkdowns of the Unit 1 and Unit 2 Reactor Containment Buildings included localized corroded embedded steel, abandoned corroded anchors, pop-outs, degraded weatherproofing (concrete joint sealant), and spalling. As part of each AR, an evaluation was performed on the extent of conditions, and the evaluations concluded that in each case the structural or functional integrity of the structure was not impacted. The ARs were closed to the work management process for implementing the necessary repairs.
- Observations during walkdowns of the Unit 1 and Unit 2 Component Cooling Water Buildings included localized concrete cracks, spalls, honeycomb and rust bleeding, degraded elastomer seals for concrete joints, corroded embedded steel in concrete, abandoned anchors in concrete, steel locations with corrosion and degraded coatings, and corroded supporting steel, handrail, and bolted connections on stairs. The conditions were evaluated and determined to be minor, and the structural and functional integrity of the structures were not impacted. The ARs were closed to the work management process for implementing the necessary repairs.
- Corrosion greater than 1/32 inches was observed on lighting conduit on the exterior east wall of the Unit 1 reactor auxiliary building. An evaluation determined that no immediate repairs were required, and that the condition did not impact the structural component's function, integrity, or ability to withstand a design basis event. The AR was closed to the work management process for implementing the necessary repairs.

<u>Program Assessments and Evaluations</u>

An assessment of the Structures Monitoring AMP and Coatings Program Roles and Responsibilities was completed in July 2019. The purpose of the assessment was to determine if the roles and responsibilities for the Structures Monitoring AMP and

Coatings Program were understood and implemented in accordance with the applicable procedures. The assessment resulted in the following actions:

- An AR was created for revision to the Structures Monitoring program implementing procedure to add references to Industry Standards for metal coatings and corresponding degradation criteria for metal coatings. This revision has been implemented.
- The Manhole Inspection work orders created for the Structures Monitoring program implementing procedure were reviewed. For work orders that did not provide for adequate notification for engineering inspection, redline markup revisions were created. The redline markups of the work orders, along with revisions to the Standardized Manhole Inspection Checklist, were uploaded into the Electronic Document Management System (EDMS). The revised manhole checklists have been added to the model work orders and are being implemented.
- Solution options were explored to address the inefficiency of the Structures Monitoring Program Database Software. The evaluation concluded that the software that was available at that time could be used to make the process marginally more efficient, but that the procurement of a new software platform that could directly access NAMS and the Health Reporting Software without the need of manual data input should be considered. A discussion on how to make tracking and reporting more efficient was uploaded into EDMS.
- A Procedure Change Request (PCR) was created to request a change to the Control of Plant Work Orders procedure that would mandate notification of and approval by Structures Monitoring AMP owner prior to cancellation or closure of Red/Yellow/White work orders.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and some findings related to the PSL Structures Monitoring AMP were identified. The Structures Monitoring AMP was identified as having a backlog of structures monitoring walkdown condition reports for acceptable conditions that do not require immediate or short-term repair. Additional resources have been applied to recover the backlog to maintain program effectiveness. The resolution of the Structures Monitoring AMP backlog is being tracked via the corrective action program.

The PSL 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 PSL Structures Monitoring AMP, with enhancements and an exception, 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.2.3.34 Inspection of Water-Control Structures Associated with Nuclear Power Plants

Program Description

The PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is an existing AMP that was evaluated as a portion of the PSL Systems and Structures Monitoring AMP in the initial license renewal application. The PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is evaluated separately in the subsequent license renewal application and it is compared to the NUREG 2191, Section XI.S7 program.

The PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is a condition monitoring AMP 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 (Section B.2.3.33) AMP. The structures within the scope of the PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP include the intake cooling water canal (the portion between the emergency cooling canal and the intake structure), emergency cooling canal, Unit 1 and Unit 2 intake structures, and ultimate heat sink dam. 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 (Section B.2.3.33) AMP. The PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants 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 video divers with videos reviewed by qualified Responsible Engineer or evaluator. Areas covered by silt, vegetation, or marine growth are not considered inaccessible and are cleaned and inspected in accordance with the standard inspection frequency. Inspection of inaccessible areas is performed under the scope of the PSL Structures Monitoring (Section B.2.3.33) AMP.

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 PSL 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 PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP, with enhancements will be consistent without exception to 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 PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants 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	Revise the implementing procedure to specify the use of high-strength bolt storage requirements discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts.
4. Detection of Aging Effects	Revise the implementing procedure to state that further evaluation of evidence of groundwater infiltration or through-concrete leakage may also include destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels, and that assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the leakage water if leakage volumes allow.
4. Detection of Aging Effects	Revise the severe weather implementing procedure to include performance of structural inspections after major unusual events such as hurricanes, floods, or seismic events.

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions. 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

The following review of plant-specific OE demonstrates how PSL is managing aging effects associated with the PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP.

- During inspection of bay 1B2 in the Unit 1 intake structure, a delaminating area was discovered at the west end of the bay, located at the east side of the guides supporting the stop logs. An evaluation determined that the delamination did not impact the SR function of the structure, the intake cooling water system, or the screen wash and circulating water pumps. A work request was initiated to dewater bay 1B2 and perform the repairs. Since the degradation did not affect the structure's intended function, the repairs were scheduled for completion during regular maintenance.
- Various concrete erosion protection on the east and west shoreline embankment south of the ultimate heat sink dam were found with cracks, concrete/grout erosion/washout, gravel washout, abandoned fence post, uneven grout settling, joint line expanded and water weeping, and vegetative growth. An evaluation determined that the ability of the system/structure/component (SSC) to perform its specified safety function and that immediate repairs were not required, but that future repairs were necessary to prevent further degradation. A work request was initiated to perform the repairs. Since the degradation did not affect the structure's intended function, the repairs were scheduled for completion during regular maintenance.
- Concrete pop-outs, corroded embedded steel, cracks, spalling, degraded coatings, and corroded abandoned anchors were identified in the Unit 2 intake structure during a Structures Monitoring (Section B.2.3.33) AMP walkdown. An evaluation determined that the identified conditions did not affect the structure's intended function, integrity, or ability to withstand a design basis event, and that immediate repairs were not necessary. A work request was initiated to complete the repairs. Since the degradation did not affect the structure's intended function, the repairs were scheduled for completion during regular maintenance.
- During a normal frequency follow-up inspection of a concrete crack documented in a previous inspection of the Unit 2 intake structure, the crack was observed with additional spalling and new rust staining in and around the crack. An evaluation determined that the degradation did not adversely impact the intake structure's function, integrity, or ability to withstand a design basis event. A work request was initiated to track coatings and repairs. Since the degradation did not affect the structure's intended function, the repairs were scheduled for completion during regular maintenance.

Program Assessments and Evaluations

The Structures Monitoring (Section B.2.3.33) AMP at PSL was placed in Maintenance Rule a(1) status in 2010 due to a negative trend in corrective action implementation and a vacancy in the Structures Monitoring (Section B.2.3.33) AMP engineering position. The last of the structures, the intake structures, were returned to Maintenance Rule a(2) status in 2014 following successful efforts to complete significant intake structure repairs, significantly reduce the backlog of work orders and fill the open position.

In 2015 and 2017, the NRC completed a Post-Approval Site Inspection for License Renewal at PSL Unit 1 and Unit 2, respectively. The inspections resulted in no findings or violations of more than minor significance.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP were identified.

The PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants 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 PSL Inspection of Water-Control Structures Associated with Nuclear Power Plants 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.2.3.35 Protective Coating Monitoring and Maintenance

Program Description

The PSL Protective Coating Monitoring and Maintenance AMP is an existing AMP that was not previously credited for license renewal. This AMP consists of guidance for selection, application, inspection, and maintenance of the Service Level I protective coatings inside the PSL 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 Revision 3) 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 D5163-08 (Reference 1.6.45) 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 PSL Protective Coating Monitoring and Maintenance AMP is a condition monitoring AMP, with scope that includes Service Level I coatings inside PSL Unit 1 and Unit 2 reactor containment buildings on both steel and concrete substrates. Per the PSL 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 PSL Protective Coating Monitoring and Maintenance AMP provides guidelines for the in-service coatings monitoring program for Service Level I coatings in accordance with ASTM D5163-08. The AMP will use the aging management detection methods, inspector qualifications, inspection frequency, monitoring and trending, and acceptance criteria defined in ASTM D5163-08, 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 D5498-12 (Reference 1.6.46).

The characterization, documentation, and testing of defective or deficient coating surfaces is consistent with ASTM D5163-08. Additional ASTM and other recognized test methods are available for use in characterizing the severity of observed defects and conditions. 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 PSL Protective Coating Monitoring and Maintenance AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.S8, “Protective Coating Monitoring and Maintenance” as modified by SLR-ISG-2021-03-Structures, Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance.

Exceptions to NUREG-2191

None.

Enhancements

The PSL Protective Coating Monitoring and Maintenance 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
3. Parameters Monitored or Inspected	Enhance the implementing documents to reference ASTM D5163-08 and clarify the parameter monitored to include blistering, cracking, rusting or physical damage.
4. Detection of Aging Effects	Enhance the implementing documents to specify that follow-up inspections will be performed by individuals trained and certified in the applicable reference standards of ASTM Guide D5498-12.
6. Acceptance Criteria	Enhance the implementing documents to include the specific inspection and documentation parameters and observation and testing methods listed in ASTM D5163-08 subparagraph 10.2.1 through 10.2.6, 10.3, and 10.4.
10. Operating Experience	Enhance the implementing documents to reference the guidance of Regulatory Position C4 of RG 1.54 Revision 3.

Operating Experience

Industry Operating Experience

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, PSL 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.

Plant Specific Operating Experience

The condition of containment coatings for PSL Units 1 and 2 is assessed each refueling outage in accordance with the PSL licensing basis. 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 ECCS operability. Minor coating repairs have been initiated where warranted to maintain or improve the margins to the design limits with respect to unqualified or degraded coatings in the containment. For example the following containment coatings results are documented in containment closeout reports and associated ARs:

- On October 28, 2016, the inspection of the Unit 1 containment coatings was completed during the refueling outage. 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 minor repairs were completed to improve the coating 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.

- On March 13, 2017, the inspection of the Unit 2 containment coatings was completed during the refueling outage. 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 minor coating repairs were completed 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.

- On March 31, 2018, the inspection of the Unit 1 containment coatings was completed during the refueling outage. 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 minor coating repairs were completed to improve the coating 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.

- On September 13, 2018, the inspection of the Unit 2 containment coatings was completed during the refueling outage. 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 minor coating repairs were completed to improve the coating 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.

- On November 15, 2019, the inspection of the Unit 1 containment coatings was completed during the refueling outage. 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 minor coating repairs were completed to improve the coating 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.

- On March 5, 2020, the inspection of the Unit 2 containment coatings was completed during the refueling outage. 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 minor coating repairs were completed to improve the coating 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.

Program Assessments and Evaluations

Since the PSL Protective Coating Monitoring and Maintenance AMP was not credited for the original license renewal, the AMP was not reviewed in the NRC Post-Approval inspection and has not been routinely evaluated in effectiveness reviews performed in accordance with NEI 14-12. Formal program health reporting has also not been required for this program at PSL.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Protective Coating Monitoring and Maintenance AMP were identified.

The PSL Protective Coating Monitoring and Maintenance 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 PSL Protective Coating Monitoring and Maintenance 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.2.3.36 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is an existing AMP, formerly a portion of the PSL Containment Cable Inspection Program. This AMP provides reasonable assurance that the intended functions of cable and connection electrical insulation exposed to adverse localized environments (ALEs) 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). ALEs 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, 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 ALE, 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 ALEs 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 earlier than 10 years prior to the SPEO and no later than six months prior to entering the SPEO. Recurring inspections are to be performed at least once every 10 years thereafter.

Site-specific OE will be evaluated to identify in-scope cable and connection insulation previously subjected to ALE during the initial PEO. 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 WO 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 PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, with enhancements, will be consistent without exception to 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 PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements 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 Expected 4. Detection of Aging Effects 10. Operating Experience	Update the governing AMP specification/procedure to do the following: • Expand scope to include cable and connection inspections outside Containment. • If cable testing is deemed necessary, utilize sampling methodology consistent with guidance of Section XI.E1 of NUREG-2191. • The program will be informed overall by awareness and review of industry OE

Operating Experience

Industry Operating Experience

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

Industry OE has shown that ALEs caused by elevated temperature, radiation, or moisture for insulated electrical cables and connections may exist. 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. These ALEs have been found to cause degradation of the insulating materials on electrical cables and connections that are visually observable, such as color changes or surface cracking. These visual indications, along with cable condition monitoring, can be used as indicators of degradation.

That industry OE 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 review of site-specific OE during the first PEO, including past corrective actions, provides objective evidence that the PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be effective in ensuring that intended functions of insulated cables and connections within the scope of the program are maintained during SPEO.

The PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is an existing AMP. A search of the AR database in the corrective action program (CAP) for electrical cable and connections discovered the following:

- In January 2015 a Unit 1 inspection in accordance with the current AMP was performed during PSL outage SL1-25. The inspection addressed non-EQ cables and connections in containment, obtained thermography readings, and there were no findings.

- In October 2012, when preparing to re-terminate the power cables to the 2A Condensate Pump, feeder cables were noted to be degraded and brittle as they entered the motor termination box. A subsequent work order was initiated by maintenance which repaired the cables.

- In September 2010 the cable connecting the rows of 1B Battery was observed to have insulation that was aging. The aging had not degraded the function of the cable or battery but was advised via the condition report to be replaced during a subsequent battery replacement. The cable was subsequently replaced.

- In October 2007 during a determination of cables within the auxiliary box located on the Unit 2 2B1 RCP, various cables were found to have been degraded. The cables were found to have brittle insulation on the individual conductors, possibly due to localized excessive heat and aging. The cables were subsequently spliced or repaired.

This plant experience demonstrates the timely identification and resolution of electrical wiring and cabling issues. This plant experience also demonstrates prompt and effective corrective actions prior to a loss of component intended function.

Program owner discussions and review of the cable system/program health reports were also performed as follows:

- Program owner discussions were conducted in December of 2020 to discuss program effectiveness. Based on these discussions, there has been no new / unexpected aging effects experienced.

- The PSL Cable Health Program is updated periodically and its health report has shown RED for several quarters. The issues which have driven the Cable Program Health Reports to be RED are primarily associated with the inaccessible power cables (underground), not with the XI.E1 visual inspection AMP. The inside containment cables have been walked down (as part of the initial license renewal), and this part of the overall PSL cable program is not identified as RED. However, the outside containment cables need to be visually inspected and the in-containment cables will also need to be walked down again, prior to the SPEO. Issues that have driven the health report to RED are addressed by their corresponding inaccessible cable AMPs.

Enhancements to the AMP have been identified and implemented as a result of OE. Examples of the AMP being enhanced by OE are industry OE events demonstrating that there are numerous cases where cables are located/routed too close to major heat-emitting plant components that are not just limited to the containment area, and do not only affect EQ cables and connections. Site-specific OE has reflected unique configurations in not-easily-accessible areas of containment that have incurred cable insulation damage from both human error (non-completion of work activities, insulation restoration, and damper louver position restoration) and close cable routing to uninsulated portions of hot process components. Prompt corrective actions were taken to prevent recurrence and evaluate if other similar configuration cases exist in other plant areas. By expanding the plant areas to be inspected in the enhanced program, and the inclusion of non-EQ insulated cables and connections, there is increased confidence that the OE is 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.

Program Assessments and Evaluations

In 2015 and 2017 per NRC IP71003, the NRC examined activities conducted under PSL'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 (References ML16004A248 and ML17334A308). The NRC reviewed the licensing basis, program basis document, implementing procedures, and interviewed the plant personnel responsible for this AMP. The NRC verified that visual inspections were performed in accordance with the program implementing procedures. Based on the results of their review, the NRC concluded that program commitments were met.

In 2019, a Self-Assessment was conducted. There were no identified gaps under the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP. This demonstrates that the existing AMP is maintained and continually monitored through the corrective action process.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program AMP were identified.

The PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification 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 PSL 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 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 used in Instrumentation Circuits

The PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP is a new AMP. This AMP will manage 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
- Control Room Air Intake Radiation Monitors

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 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 ALEs 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.

As an alternative to the review of calibration results described above, direct testing of the cable system may be performed. This applies to cables in the scope of the program that are disconnected during instrument calibration using a proven method for detecting deterioration for the insulation system. This can be one or more of the following tests: insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation physical, mechanical, and chemical properties, as applicable. 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. However, inspection and test results that are trendable provide additional information on the rate of cable or connection degradation.

In accordance with the PSL 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 PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP will be consistent without exception to 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>

PSL evaluates industry OE items for applicability per the NextEra Energy Fleet OE Program and takes appropriate corrective actions.

Industry OE 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

There were no program health reports since this program is new and not yet implemented.

A review of five quarterly radiation monitoring system health reports covering the period from the fourth quarter (Q4) of 2019 through Q4 2020 was conducted to determine system performance during PEO. The review indicated that the radiation monitoring system has been functioning well during this review period. The system has been incurring various issues affecting the varying overall system health ratings (RED, YELLOW, WHITE, and GREEN). Maintenance Rule performance has been inconsistent and incurs a RED status whenever a performance goal is not met for that quarter (Maintenance Rule Functional Failures - MRFFs). The digital loop communication system was installed in the 1980s and was incurring performance reliability issues; therefore, the system was replaced in 2020. A major activity during this period was to identify area radiation monitors not vital for system function or safety and remove them from service to dedicate site maintenance resources on those that are important. Other common issues such as replacing spent monitors and detectors were incurred during this time period.

In January 2005, an ARM cable was noted out of service for 5 months. This was a non-Tech Spec ARM and was determined to be removed under the ARM reduction effort to improve maintenance practices on the more vital RMs.

In May 2010, an erratic ARM cable signal was detected. Further investigation concluded that this was due to a bad or loose connector. The connector was replaced and the circuit signal was restored to original signal quality.

In June 2014, a Linear Power Range Safety Power channel began to show erratic behavior. The channel indicated Nuclear Power rose to approximately 56 percent. The channel Reactor Protection System (RPS) Variable Hi Power pre-trip and trip came into alarm. Troubleshooting attempts could not locate the cause or recreate the erratic signals. Suspected cause indicated the temperature adjustment electronics associated with the A11 board. Replacement of the circuit board was completed at the next opportunity.

In September 2015, after reenergizing the 'B' channel powered nuclear instrumentation, the system began behaving erratically and fluctuating constantly. Troubleshooting included testing of the circuit with "SAT" results. The detector was checked with a megger and all readings were "SAT". When the detector was reconnected, the noise and bouncing did not appear on the meter. The system was calibrated with "SAT" results. The connection of the detector was cleaned before the installation. It appears the fault was the connector being dirty.

In September 2015, a radiation monitor cable appeared degraded and brittle. Cable testing of the circuit provided "SAT" results. The aging effect was limited to the jacket and the insulation condition and function remain intact. No cable replacement was required.

In October 2015, a containment post LOCA radiation monitor signal was spiking. Replacement of the cable was conducted and connected. Cause was suspected to be from a dirty/loose connection.

In July 2018, it was found that a radiation monitor was out of service. The channel signal was extremely low. By manipulating the monitor cable, it resulted in the signal coming in and out. The cause for the interrupted circuit cable was broken somewhere internally and needed to be changed out. Replacement of the cable was conducted and connected. Cause of the broken signal cable was removing and reconnecting the cable per the Maintenance Activity.

In August 2018, during the initial walkdown of the Unit 2 Containment High Range Radiation Monitor System (CHRRMS) detector signal cable routing in containment, the EQ splice sealing sleeve for the detector signal cable and the high-voltage cable for RD-26-41 were found not to be shrunk to the cables to form the seal and with paper inside the open sealing sleeve. The EQ seal of the high-voltage cable was redone to provide reasonable assurance it is EQ qualified. The cause was attributed to an improper splice.

In September 2018, during installation of a Safety Linear Power Range Detector, pre-service checks were conducted using acceptance criteria of Insulation Resistance of Shield to Ground. The As-Found results did NOT provide consistent acceptable readings. The readings varied significantly with movement of the cable assembly. This Unit 2 neutron detector assembly was replaced. Cause was suspected to be a loose or worn connector/connection.

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 PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits 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 PSL Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits 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.2.3.38 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The PSL Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP. The purpose of the PSL 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 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 medium-voltage cable exposure to significant moisture will 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 inspections will occur at least once annually with the first inspection for SLR completed no later than six months prior to entering the SPEO if a water level monitoring system is not installed. 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, or flooding. Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant operating experience. Inspections of manholes equipped with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent level alarm). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or the control room. Reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

Inspection of manholes with water level monitoring and alarms are performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). Parameters will be established for the initiation of an event driven inspection. Inspections will 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 will be 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 will be initiated, the source of the water intrusion will be determined, and age-related degradation of the cable insulation will be assessed.

Inaccessible non-EQ medium-voltage power cables within the scope of SLR exposed to significant moisture will be tested to determine the age-related degradation of their electrical insulation.

The first tests for SLR will 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. PSL specific inaccessible medium-voltage power cable procedure(s) will be 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 will be inspected, and their operation will be 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 PSL Structures Monitoring (Section B.2.3.33) AMP. The PSL 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 PSL 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 PSL Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirement AMP will be consistent without exception to 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 NRC SLR-ISG-2021-04-ELECTRICAL, “Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

OE has shown that medium-voltage power cable electrical insulation materials undergo increased age-related 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-related degradation of electrical insulation. Minimizing exposure to significant moisture mitigates the potential for age-related degradation. The PSL program will be based on the program description in NUREG-2191 XI.E3A, which in turn is based on industry OE.

By way of background, NRC Information Notice 2002-12, issued March 21, 2002, informed licensees of observed submergence in water of electrical cables that feed SR equipment. The bulletin detailed accounts of leaking duct banks, cable jacket tears, and multiple instances of submerged cables in manholes. NRC IN 2010-26, Submerged Electrical Cables, informed licensees of other plants underground power cable failures citing lack of condition monitoring (testing) to detect cable insulation aging. 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. PSL submitted a formal response to NRC Generic Letter 2007-01, under letter NRC L-2007-067 dated May 8, 2007. This documented response detailed three underground power cable-related positions / issues as follows:

- At PSL, there have been no in-scope 10 CFR 50.65 inaccessible or underground power cable failures. This determination was rendered through reviews of condition reporting databases, the work control database, and the Cable and Raceway Schedule.

- One Unit 1 LV AC power cable that was tested during the spring 2007 refueling outage was identified as degraded. The degraded cable was a 480-volt power cable for a Unit 1 containment penetration feedthrough cable. The cable was identified by a low megger reading on the C-Phase conductor located between the containment annulus and the outer containment concrete wall. The cable was replaced to prevent potential future failure. The cause of the cable's low megger reading was not related to an underground high-moisture environment addressed under this program.

- PSL has a manhole inspection program for SR manholes to determine that they are clean, dry, confirm that the sump pump is working (if applicable) and to repair any age-related degradation to the cable insulations or manhole.

> The objective of this program is to provide assurance that the systems designed to minimize the amount of time the cable is exposed to a wet environment are operational. The current inspection cycle is every 2 years. The program is controlled via a preventive maintenance program activity. Manholes are sealed to prevent most moisture intrusion, and those manholes without sump pumps drain to manholes having sump pumps. Periodic cable testing is done as part of the normal plant preventive maintenance programs.

The manhole inspections described in PSL's response to GL 2007-01 included a commitment specific to the structural inspection (walls and cable trays) conducted under the Structures Monitoring (Section B.2.3.33) AMP.

Plant-Specific Operating Experience

The following examples of OE provide objective evidence that the PSL Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirement AMP will be effective in ensuring that component intended functions are maintained consistent with the CLB during the SPEO.

Program owner discussion was conducted in December 2020 and addressed the existing medium-voltage cable monitoring actions. The site cable condition monitoring program (CCMP) was issued in 2011 but is not credited for original license renewal.

A review of five quarterly Cable Health Program health reports covering the period from the fourth quarter (Q4) of 2019 through Q4 2020 was conducted to determine cable program performance. The existing cable program system had been incurring various persistent issues concerning cable tests and manhole inspections, such as manhole inspections still discovering cables submerged, degraded manhole conditions, no qualified site cable program engineer qualifications, and no consistent periodic manhole program implementation to attain optimum manhole inspection periodicity based upon plant manhole inspection data. An AR was generated to document these conditions which generated an action plan for resolution.

A search of the AR database in the corrective action program (CAP) for underground medium cables and manholes revealed multiple ARs during the early implementation of this program (2010-2020 timeframe). The ARs did indicate the absence of any underground medium-voltage power cable failures but do reflect a challenging high-moisture environment on the metallic components (cable supports and manhole covers), blocked drainage pathways, unacceptable water accumulation levels, and sump pump failures. The AR action plan will provide reasonable assurance that water levels in the manholes are maintained below the cables and their supports, sump pump operability is periodically verified and drainage paths periodically checked for obstructions. Cable tests will consistently be conducted and records maintained for trending. An AR provides a summary of the issues and an Action Plan to implement appropriate corrective actions.

In February 2011, an AR identified that the station inspection and trending of cables and manholes was behind schedule. In response, PSL has performed or initiated the following actions: 1) Inspected all Priority Level 1 and 2 manholes at least once,

2) Developed an Access database of all the manholes at PSL to track and trend the results of the manhole inspections, 3) Developed monthly PMs for “wet” manholes, and 4) Began weekly meetings with Work Controls, Engineering and Maintenance to improve communication on manhole inspection progress and problems.

In January 2012, during inspection of a manhole, the drain was found clogged and cables were submerged. Per the CCMP, submerged cables need to be evaluated for health of the insulation. The critical cables were associated with Unit 2 SR B Train. The cables were insulation resistance tested and determined to be in satisfactory condition.

In April 2013, an inspection revealed about 18" of water in a manhole. There were indications that the water level had been higher in the past and that the cables had been submerged for extended periods. After removing water the sump was found to have a plywood form in it (from the early 1970s). The plywood and water were removed. The submerged cables are non-safety related low voltage security system cables. Previous testing of similar submerged low voltage cables found no issues.

In July 2013, while performing a preventive maintenance (PM) activity of SR manholes, maintenance conducted an inspection of a manhole. Upon removing cover, about 3 ft of water was found in the manhole. The manhole had a permanent sump pump but its associated electrical receptacle was degraded. The receptacle was tested satisfactorily but the sump was not working properly. The sump pump was replaced and tested satisfactorily. There were 2 conduits about 3 or 4 inches in diameter that were sitting in water with corrosion. Corrective actions included megger testing and other improvements. The sump pump was subsequently replaced, and the power outlet was repaired in 2013.

In March 2013, during an NRC Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdown per TI 2515/187, the drain for a Unit 1 manhole was identified as partially blocked due to debris and corrosion related by-products that were collecting at the opening to the drain. There was no standing water in the manhole, and the drain opening appeared to be passable. If the condition was not addressed, it could eventually degrade sufficiently to block the drain and result in potential flooding of the manhole. Conduits penetrating SR structures were sealed to prevent water intrusion and potential flooding concerns that may result in adverse impacts to SR systems or components. The cables are not currently wetted, and there is no evidence of the cables being wetted. Based on review of Work Orders, the last time this manhole was inspected was October 2011. The manhole drain was cleaned and debris removed from the manhole.

In October 2013, inspections at PSL Unit 2 identified 8 manholes that were found containing water. An AR documents the engineering review and corrective actions completed. Engineering determined the total population of cables within the manholes and recommended insulation resistance (IR) testing to determine if they were degraded. All tested cables met the recommended minimum IR values.

In July 2016, electricians identified degraded cable supports in a manhole east of U2 fuel handling building. A subsequent engineering examination of the manhole confirmed that at least five cable supports had degraded and required restoration. The degradation was a result of poor water draining into the storm drain system, so the supports were periodically submerged in water. The cable insulation appeared to be in fair condition, and not deteriorated. The first action was to first clean-out the floor drain to eliminate water collection. Based on inspection of the cables and supports, new cable supports were installed.

In October 2019, there was an identified manhole drainage issue from a number of manholes to a catch basin. These manholes contained cables that were both SR and important to safety. The drain flow path was determined to be collapsed/clogged so the affected manholes could not drain to the catch basin. Thus, the cables routed in these manholes have been subjected to long-term exposure (and in some cases partial submergence) because of water retention. Work orders were generated to repair the drainage pathway, which are included in the cable program action plan identified below. Additionally, work orders were prepared to perform insulation testing on all the affected SR and important to safety cables.

In October 2019, the cable program was integrated with the manhole program. A PM change request was approved to establish a 12 month PM inspection frequency to establish baseline trending for some manhole PMs. The purpose of the PM trending is to establish the proper periodicity to prevent water in the manholes at the time of each inspection. On the three occasions for one of the PM WOs water was found in the manholes, indicating that drainage was inadequate. Adequate drainage is being addressed in the cable program action plan. Implementation of the new SLR XI.E3A program will optimize manhole inspection frequencies to ensure cables in the scope of the program and their respective supports are prevented from being submerged.

In July 2020, water was found in a manhole and had to be removed with a temporary sump pump because the installed sump pump was not working. There also were several insulators that came loose inside the manhole. These insulators were repaired and reattached, and the installed sump pump was repaired .

In April 2021, the GL 2007-01 Cable Manhole Inspection Program was identified as requiring certain corrective actions. Many are being resolved through Yellow Work Orders that have established scheduled dates for completion of manhole inspections and repairs. The program is being assessed by this AR with tracking mechanisms to ensure resolutions facilitate implementation of the current GL 2007-01 program. Four main issues are targeted for the required improvements:

1) Timely completions of SR Cable Manhole Inspections, and schedule future PMs.

2) Completion of SR Cable Manhole drain path repairs, sump pump to ensure no prolonged cable (or cable support) submergence conditions.

3) Repair of the collapsed/blocked catch basin drain path of the (cascading drainage path) manholes associated with the catch basin.

4) Evaluation of the installation of a cable manhole level monitoring system to allow a 5 year manhole inspection interval and waiving of manhole inspections after heavy rain. (If implemented, modification would be installed prior to SPEO).

The GL 2007-01 Cable Manhole Inspection Program Engineer developed an action plan from this AR to complete PMs and repairs.

Inspection frequencies will be adjusted based on inspection results including site specific OE but with a minimum inspection frequency of at least once annually. Inspection frequency can be changed to 5 years and event based inspections waived if a cable manhole level monitoring system is installed. Site-specific OE will be used in the adjustment of the inspection frequency of this AMP. The AMP will be adjusted as necessary as additional site-specific OE is accumulated to provide reasonable assurance that the cables are kept free from significant moisture.

The manholes within the scope of this new AMP will be visually inspected periodically based on water accumulation over time. Inspection frequencies will be adjusted based on inspection results including site specific OE but with a minimum inspection frequency of at least once annually. Inspection frequency can be changed to 5 years and event based inspections waived if a cable manhole level monitoring system is installed. Site specific OE will be used to adjust the inspection frequency for this AMP. The AMP will be adjusted if necessary as additional site specific OE is accumulated to provide reasonable assurance that the 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 PSL Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification 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 PSL Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirement 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.2.3.39 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The PSL 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 that are within the scope of SLR and potentially 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 is a condition monitoring AMP. However, this AMP also 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 if a water level monitoring system is not installed. Inspections are also performed after event-driven occurrences, such as heavy rain or flooding. Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant operating experience. Inspections of manholes equipped with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent level alarm). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or the control room. Reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

Inspection of manholes with water level monitoring and alarms are performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms).

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-related 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 in-service 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, in-service application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed in-service inaccessible I&C cables when testing is required in this AMP.

NUREG-2191 Consistency

The PSL Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be consistent without exception to 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-2021-04-ELECTRICAL, “Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance”.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

OE has shown that cable electrical insulation materials undergo increased degradation through aging mechanisms when subjected to significant moisture. Inaccessible I&C 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 PSL program will be based on the program description in NUREG-2191 XI.E3B, which in turn is based on industry OE.

By way of background, NRC IE Notice 2002-12, issued March 21, 2002, informed licensees of observed submergence in water of electrical cables that feed SR equipment. The bulletin detailed accounts of leaking duct banks, cable jacket tears, and multiple instances of submerged cables in manholes. NRC IN 2010-26, Submerged Electrical Cables, informed licensees of other plants underground power cable failures citing lack of condition monitoring (testing) to detect cable insulation aging. 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. PSL submitted a formal response to NRC Generic Letter 2007-01, under letter NRC L-2007-067 dated May 8, 2007. This documented response detailed three underground power cable-related positions / issues as follows:

- At PSL, there have been no in-scope 10 CFR 50.65 inaccessible or underground I&C cable failures. This determination was rendered through reviews of condition reporting databases, the work control database, and the Cable and Raceway Schedule.
- One Unit 1 AC LV power cable that was tested during the spring 2007 refueling outage was identified as degraded. The degraded cable was a 480-volt power cable for a Unit 1 containment penetration. The condition was identified by a low megger reading on the C-Phase conductor located between the containment annulus and the outer containment concrete wall. The cable was replaced to prevent potential future failure. The cause of the cable's low megger reading was not related to an underground high-moisture environment addressed under this program.
- PSL has a manhole inspection program for SR manholes to determine that they are clean, dry, that the sump pump is working (if applicable) and to repair any degradation to the cables or manhole. The objective of this program is to provide assurance that the systems designed to minimize the amount of time the cable is exposed to a wet environment are operational. The current inspection cycle is every 2 years. The program is controlled under a preventative maintenance program activity. Manholes are sealed to prevent most moisture intrusion and drain to manholes with sumps. Periodic cable testing is done as part of the normal plant preventive maintenance programs.

The manhole inspections described in PSL’s response to GL 2007-01 included a commitment specific to the structural inspection (walls and cable trays) conducted under the Structures Monitoring (Section B.2.3.33) AMP.

<u>Plant-Specific Operating Experience</u>

The following examples of OE provide objective evidence that the PSL Electrical Insulation for Inaccessible Instrument and Control 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 program owner discussion was conducted in December 2020 and addressed the existing cable monitoring actions. The site Cable Condition Monitoring Program (CCMP) was issued in 2011 but is not credited for original license renewal. The PSL Electrical Insulation for Inaccessible I&C Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new program, the implementation of which has not yet been observed.

A review of five quarterly cable health program health reports covering the period from the fourth quarter (Q4) of 2019 through Q4 2020 was conducted to determine cable program performance. The existing cable program has been incurring various persistent issues concerning cable tests and manhole inspections, such as manhole inspections still discovering cables submerged, degraded manhole conditions, site cable program engineer qualifications and no consistent periodic manhole program to attain optimum manhole inspection periodicity based upon inspection data. An action request was generated to document these conditions which generated an action plan for resolution.

A search of the AR database in the corrective action program (CAP) for underground cables and manholes revealed multiple ARs during the early implementation of this program (2010-2020 timeframe). The ARs reflected the absence of any underground I&C power cable failures but did indicate a challenging high-moisture environment on the metallic components (cable supports and manhole covers), blocked drainage pathways, unacceptable water accumulation levels and sump pump failures. The AR action plan will provide reasonable assurance that water levels in the manholes are maintained below the cables and their supports, sump pump operability is periodically verified and drainage paths periodically checked for obstructions. Cable tests will consistently be conducted and records maintained for trending. An AR provides a summary of the issues and an Action Plan to implement appropriate corrective actions.

In January 2012, during inspection of a manhole, the drain was found clogged and cables were submerged. Per the CCMP, submerged cables need to be evaluated for health of the insulation. The cables were associated with Unit 2 SR B Train. The cables were insulation resistance tested to determine satisfactory condition.

In April 2013, an inspection revealed about 18 inches of water in a manhole. There were indications that the water level had been higher in the past and that the cables had been submerged for extended periods. After removing the water, the sump was found to have a plywood form in it from the early 1970s. The plywood and water were removed and megger testing of the cables was performed.

In March 2013, during an NRC inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdown per TI 2515/187, the drain for a Unit 1 manhole was identified as partially blocked due to debris and corrosion related by-products that were collecting at the opening to the drain. There was no standing water in the manhole, and the drain opening appeared to be passable. If the condition had not been addressed, it could eventually degrade sufficiently to block the drain and result in potential flooding of the manhole. Conduits penetrating SR structures were sealed to prevent water intrusion and potential flooding concerns. Although the cables can function in a submerged condition, the cables were not wetted. Based on review of WOs, the last time this manhole was inspected was October 2011. The manhole drain was cleaned and debris removed from the manhole.

In July 2013, while performing a PM of SR manholes maintenance found about 3 feet of water in a manhole (which was removed). The manhole had a permanent sump pump, but its associated electrical receptacle was degraded. The receptacle was tested satisfactorily, but the pump was not working properly. The sump pump was replaced and tested satisfactorily. There were 2 conduits about 3 or 4 inches in diameter that were sitting in water with corrosion on them. Corrective actions included megger testing.

In July 2016, electricians identified the degraded cable supports in a manhole east of the Unit 2 fuel handling building. A subsequent engineering examination of the manhole confirmed that at least five cable supports have degraded and required restoration. The degradation was a result of poor water draining into the storm drain system, so the supports sometimes are periodically submerged in water. The cable insulation appeared to be in fair condition and not deteriorated. The first action was clean-out the floor drain to eliminate water collection. Based on inspection of the cables and supports, new cable supports were installed.

In October 2019, there was an identified manhole drainage issue from a number of manholes to a catch basin. These manholes contain cables that are both SR and important to safety. The drain flow path was determined to have collapsed or clogged, so the affected manholes could not drain to the catch basin. Thus, the cables routed in these manholes have been subject to long-term exposure because of water retention. Work orders were generated to repair the drainage pathway, which are included in the cable program action plan identified below. Additionally, WOs were prepared to perform insulation resistance testing on all the affected SR and important to safety cables.

In October 2019, the cable program was integrated with the manhole program. A PM change request was approved to establish a 12 month PM inspection frequency to establish baseline trending for some manhole PMs. The purpose of the PM trending was to establish the proper periodicity to prevent water in the manholes at the time of each inspection. On the three occasions for one of the PM WOs water was found in the manholes, indicating that drainage was inadequate. Adequate drainage is being addressed in the cable program action plan. The implementation of the new SLR XI.E3C AMP will optimize manhole inspection frequencies to ensure cables in the scope of this program and their respective supports are prevented from being submerged.

In July 2020, water was found in a manhole and had to be removed with a temporary pump because the installed sump pump was not working. This was an ongoing issue that needed to be repaired. There were several insulators that came loose inside this manhole. These insulators were repaired and reattached, and the installed sump pump was repaired.

In April 2021, the GL 2007-01 Cable Manhole Inspection Program was identified as having some conditions requiring corrective actions. Many are being resolved through Yellow Work Orders that have established scheduled dates for completion of manhole inspections and repairs. The program is being assessed by this AR with tracking mechanisms to ensure resolutions facilitate implementation of the current GL 2007-01 program. Four main issues are targeted for the required improvements:

1) Timely completions of SR Cable Manhole Inspections, and schedule future PMs.

2) Completion of SR Cable Manhole drain path repairs and sump pump repairs to ensure no prolonged cable (or cable support) submergence conditions.

3) Repair the collapsed/clogged ECB#1 drain path of the (cascading drainage path) manholes associated with ECB#1,

4) Evaluation of the installation of a cable manhole level monitoring system to allow a 5 year manhole inspection interval and waiving of manhole inspections after heavy rain. If implemented, modification would be installed prior to SPEO.

The GL 2007-01 Cable Manhole Inspection Program Engineer is to develop action plan from this AR to complete PMs and repairs.

The manholes within the scope of this new AMP will be visually inspected periodically based on water accumulation over time. Inspection frequencies will be adjusted based on inspection results including site specific OE but with a minimum inspection frequency of at least once annually. Inspection frequency can be changed to 5 years and event based inspections waived if a cable manhole level monitoring system is installed. Site-specific OE will be used to adjust the inspection frequency for this AMP. The AMP will be adjusted if necessary as additional site-specific OE is accumulated to provide reasonable assurance that the 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 PSL Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification 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 PSL Electrical Insulation for Inaccessible Instrumentation and Control 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 Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The PSL Electrical Insulation for Inaccessible Low Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP for SLR. The purpose of the PSL 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 power cables, including those designed for continuous wetting or submergence, within the scope of SLR potentially 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 AMP. 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 if a water level monitoring system is not installed. 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 PSL Structures Monitoring AMP (Section B.2.3.33).

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 or flooding. Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant operating experience. Inspections of manholes equipped with water level monitoring and alarms are also performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent level alarm). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or the control room. Reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

Inspection of manholes with water level monitoring and alarms are performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). 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 OE.

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-related degradation of the cable jacket may indicate accelerated age-related 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-related 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-related degradation. One or more tests may be required based on cable type, application, and electrical insulation material to determine the age-related degradation of the cable insulation. Testing of installed in-service 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, in-service application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed in-service 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 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.

The AMP is to be implemented with inspections completed no later than six months prior to entering the SPEO.

NUREG-2191 Consistency

The PSL Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be consistent without exception to 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-2021-04-ELECTRICAL, “Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance”.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

OE has shown that cable electrical insulation materials undergo increased degradation through aging mechanisms when subjected to significant moisture. Inaccessible I&C 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 PSL program will be based on the program description in NUREG-2191 XI.E3C, which in turn is based on industry OE.

By way of background, NRC Information Notice 2002-12, issued March 21, 2002, informed licensees of observed submergence in water of electrical cables that feed SR equipment. The bulletin detailed accounts of leaking duct banks, cable jacket tears, and multiple instances of submerged cables in manholes. IN 2010-26, Submerged Electrical Cables, informed licensees of other plants underground power cable failures citing lack of condition monitoring (testing) to detect cable insulation aging. NRC Generic Letter 2007-01, issued February 7, 2007 further cited NRC IN 2002-12 and informed licensees of these cable failures and asked them to provide information on the monitoring of inaccessible or underground electrical cables. PSL submitted a formal response to NRC Generic Letter 2007-01, under letter L-2007-067 dated May 8, 2007. This documented response detailed three underground power cable-related positions / issues as follows:

- At PSL, there have been no in-scope 10 CFR 50.65 inaccessible or underground LV power cable failures. This determination was rendered through reviews of condition reporting databases, the work control database, and the Cable and Raceway Schedule.
- One Unit 1 LV AC power cable that was tested during the spring 2007 refueling outage was identified as degraded. The degraded cable was a 480-volt power cable (a feedthrough) for a Unit 1 containment penetration. The cable was identified by a low megger reading on the C-Phase conductor located between the containment annulus and the outer containment concrete wall. The cable was replaced to prevent potential future failure. The cause of the cable's low megger reading was not related to an underground high-moisture environment addressed under this program.
- PSL has a manhole inspection program for SR manholes to determine that they are maintained clean, dry, confirm that the sump pump is working (if applicable), and to repair any degradation to the cables or manhole. The objective of this program is to provide assurance that the systems designed to minimize the amount of time the cable is exposed to a wet environment are operational. The current inspection cycle is every 2 years and the program is a License Renewal commitment for both Units at the site. The program is controlled under a preventative maintenance program activity. Manholes are

sealed to prevent most moisture intrusion, and those without sump pumps drain to manholes having sump pumps. Periodic cable testing is done as part of the normal plant preventive maintenance programs.

The manhole inspections described in PSL's response to GL 2007-01 included a commitment specific to the structural inspection (walls and cable trays) conducted under the Structures Monitoring (Section B.2.3.33) AMP.

Plant-Specific Operating Experience

The following examples of OE provide objective evidence that the PSL Electrical Insulation for Inaccessible Low-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.

Program owner discussion was conducted in December 2020 and addressed the existing low-voltage power cable monitoring actions. The site cable conditioning monitoring program (CCMP) was issued in 2011 but is not credited for original license renewal. The PSL Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new program, the implementation of which has not yet been observed.

A review of five quarterly Cable Health Program health reports covering the period from the fourth quarter (Q4) of 2019 through Q4 2020 was conducted to determine cable program performance. The existing cable program had been incurring various persistent issues concerning cable tests and manhole inspections, such as manhole inspections still discover cables submerged, degraded manhole conditions, site cable program engineer qualifications and no consistent periodic manhole program implementation to attain optimum manhole inspection periodicity based upon plant manhole inspection data. An action request was generated to document these conditions which generated an action plan for resolution.

A search of the AR database in the corrective action program (CAP) for underground low-voltage power cables and associated manholes revealed multiple ARs during the early implementation of the medium-voltage and low-voltage power cable management under the CCMP (2010-2020 timeframe). The ARs reflected the absence of any underground low-voltage power cable failures, but they did reflect a challenging high-moisture environment on the metallic components (cable supports and manhole covers), blocked drainage pathways, unacceptable water accumulation levels, and sump pump failures. The AR action plan will provide reasonable assurance that water levels are maintained below the cables and their supports, sump pump operability is periodically verified and drainage paths are periodically checked for obstructions. Cable tests will consistently be conducted, and records are maintained for trending. An AR provides a summary of the issues and an Action Plan to implement appropriate corrective actions.

In February 2011, station inspection and subsequent trending of cables and manholes was identified as being behind schedule. The following work remained incomplete: schedule and complete identification and classification of manholes at PSL, schedule and complete initial inspection of manholes with SR cables, schedule and complete inspection of higher priority manholes (manholes with critical cables security, production, etc.) and schedule and complete monthly inspection of wet manholes. Most of these efforts were subsequently completed, although some work is scheduled for completion.

In January 2012, during inspection of a manhole, it was found clogged and the cables were submerged. Per the CCMP, submerged cables need to be evaluated for health of the insulation. The critical cables were Unit 2 SR B Train items. These cables were insulation resistance tested to determine satisfactory condition.

In April 2013, on inspection revealed about 18" of water in a manhole. There were indications that the water level had been higher in the past and that the cables had been submerged for extended periods of time. After removing water, the sump was found to have a plywood form in it from the early 1970s (from construction). The plywood and water were removed and megger testing of the cables was performed.

In July 2013, while performing a preventive maintenance (PM) activity of SR manholes, maintenance conducted an inspection of a manhole. Upon removing the cover, about 3 feet of water was found in the manhole and the water was removed. The manhole had a permanent sump pump, but its associated electrical receptacle was degraded. The receptacle was tested satisfactorily, but the sump was not working properly. The sump pump was replaced and tested satisfactorily. There were 2 conduits about 3 or 4 inches in diameter that were sitting in water with corrosion. Corrective actions included megger testing and other manhole improvements.

In March 2013, during an NRC Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdown per TI 2515/187, the drain for a Unit 1 manhole was identified as partially blocked due to debris and corrosion related by-products that were collecting at the opening to the drain. There was no standing water in the manhole, and the drain opening appeared to be passable. If the condition was not addressed, it could eventually degrade sufficiently to block the drain and result in potential flooding of the manhole. Conduits penetrating SR structures were sealed to prevent water intrusion and potential flooding concerns that may result in adverse impacts to SR systems or components. The cables are not wetted, and there is no evidence of the cables being recently wetted. Based on review of Work Orders, the last time this manhole was inspected was October 2011. The manhole drain was cleaned and debris was removed from the manhole.

In October 2013, inspections at PSL Unit 2 identified 8 manholes that were found containing water. An AR documents the engineering review and corrective actions completed. Engineering determined the total population of cables within the manholes and recommended insulation resistance (IR) testing to determine if they were degraded. All tested cables met the recommended minimum IR values.

In July 2016, electricians identified degraded cable supports in a manhole east of the Unit 2 fuel handling building. A subsequent engineering examination of the manhole confirmed that at least five cable supports had degraded and required restoration. The degradation was a result of poor drainage from the manhole into the storm drain system, so the supports were periodically submerged in water. The cable insulation appeared to be in fair condition and not deteriorated. The first action was to clean out the floor drain to eliminate water collection. Based on inspection of the cables and supports, new cable supports were installed.

In September 2018, an assessment was performed to determine if the roles and responsibilities for the structures monitoring program (SMP) and coatings program were understood and implemented in accordance with the applicable procedures. There was an influx of ARs/WRs/WOs created in NAMS that were also entered into a database (as a result of the license renewal walkdowns).

An example of this was manhole inspections. Some of the inspections were required per the SMP, some were Fukushima response items, some were SR, and some were security items. The SMP Owner or qualified inspector needed to be notified when the manholes would be open and available for inspection. In a majority of cases, the SMP Owner was not notified that an inspection was required until the day the manhole was being worked.

The requested resolution actions were to review all model work orders and create procedure change requests (PCRs) to revise the model WOs to include required wording and add WO tasks for the SMP owner inspection. A database will be created to communicate with NAMS and Health Reporting Software, complete with training for users to eliminate searching NAMS for updating WO status, track trends, and cancelations. A requirement will be added such that program/system owners will be notified and provided with justification before canceling WOs.

In October 2019, there was an identified manhole drainage issue from a number of manholes to a catch basin. These manholes contained cables that were both SR and important to safety. The drain flow path was determined to be collapsed/clogged the affected manholes could not drain to the catch basin. Thus, the cables routed in these manholes have been subject to long-term exposure (and in some cases partial submergence) because of water retention. Work orders were generated to repair the drainage pathway, which are included in the cable program action plan identified below. Additionally, works orders were prepared to perform insulation resistance testing on all the affected SR and important to safety cables.

In October 2019, the cable program was integrated with the manhole program. A PM change request was approved to establish a 12 month PM inspection frequency to establish baseline trending. The purpose of the PM trending was to establish the proper periodicity to prevent water in the manholes at the time of each inspection. On three occasions, for one of the PM WOs, water was found in the manholes indicating that drainage was inadequate. Adequate drainage is being addressed in the cable program action plan. Implementation of the new XI.E3B AMP will optimize manhole inspection frequencies to ensure cables in the scope of this program and their respective supports are prevented from being submerged.

In July 2020, water was found in a manhole and had to be removed with a temporary pump because the installed sump pump was not working. This was/is an ongoing issue that needed to be repaired. There were several insulators that came loose inside this manhole. These insulators were repaired and reattached, and the installed sump pump was repaired.

In April 2021, the GL 2007-01 Cable Manhole Inspection Program was identified as requiring corrective actions. Many are being resolved through WOs that have established scheduled dates for completion of manhole inspections and repairs. The program is being assessed with tracking mechanisms to confirm resolutions facilitate implementation of the current GL 2007-01 program. Four main issues are targeted for the required improvements:

1) Timely completions of SR cable manhole inspections, and scheduling of future PMs.

2) Completion of SR cable manhole drain path repairs and sump pump repairs to ensure no prolonged cable (or cable support) submergence conditions.

3) Repair of the collapsed/blocked cascading drain path of the manholes.

4) Evaluation of the installation of a cable manhole level monitoring system to allow a 5 year manhole inspection interval and waiving of manhole inspections after heavy rain. (If implemented, modification would be installed prior to SPEO).

The GL 2007 01 Cable Manhole Inspection Program Engineer developed an action plan from this AR to complete PMs and repairs.

The manholes within the scope of this new AMP will be visually inspected periodically based on water accumulation over time. Inspection frequencies will be adjusted based on inspection results including site specific OE but with a minimum inspection frequency of at least once annually. Inspection frequency can be changed to 5 years and event based inspections waived if a cable manhole level monitoring system is installed. Site specific OE will be used to adjust the inspection frequency for this AMP. The AMP will be adjusted if necessary, as additional site specific OE is accumulated to provide reasonable assurance that the 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 PSL Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification 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 PSL 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.2.3.41 Metal Enclosed Bus

Program Description

The PSL 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 PSL Metal Enclosed Bus (MEB) AMP is to provide reasonable assurance that the intended functions of metal enclosed buses in the 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 PSL Structures Monitoring (Section B.2.3.33) AMP. The external portions of the MEB, including accessible gaskets 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.

Under the new AMP, 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 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. The connections will be tested with a micro-ohmmeter.

MEB external surfaces and structural supports are inspected under the PSL Structures Monitoring (Section B.2.3.33) AMP 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 show a low resistance value appropriate for the application when resistance measurement is used.

As an alternative to measuring connection resistance of bolted connections, for accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., PSL 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 PSL Metal Enclosed Bus AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.E4, “Metal Enclosed Bus.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

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.

Plant Specific Operating Experience

A search of plant records showed the following events for the Metal Enclosed Bus at PSL:

In October of 2012, there was a failure of a non-segregated bus (NSB) 6.9kV bus. This caused a transformer lockout, thus tripping both the 6.9kV and the 4kV buses supplying power to B-train components. The event also caused a loss of offsite power and an emergency diesel generator (EDG) start. The failure was caused by a rusted vent screen. The preventive maintenance (PM) requirement and the system monitoring plan were revised to implement periodic inspection of the NSB run enclosure vents for visible external corrosion during quarterly system walkdowns.

In September of 2015, there was a failure of a 6.9kV NSB. This event documented conditions causing a path for a phase-to-phase fault on the 6.9kV bus. This condition led to a transformer lockout, thus tripping both the faulted 6.9kV bus and the 4kV buses feeding A-train components. This event also caused a startup (S/U) transformer lockout on the opposite running Unit A-train S/U transformer. The event led to additional changes and addressed issues within the already established NSB PM program. Implementation of the PMs was reinforced, and the work scope better defined for supporting thorough NSB inspections. NSB runs were also further split to facilitate inspections in sections that were never inspected before.

In January of 2016, during scheduled work activities for a 6.9kV bus, the B phase at the bus joint was found with a burned-out boot (this joint is a bottom 90-degree connection). The bus joint and its bolting hardware were also found to be corroded. The insulating boots for the A and C phases had also signs of overheating. The bus joint was located right above a bus heater, which appeared to be the source of the overheating conditions seen in the insulating boots. Maintenance also reported the boot in the B-phase had apparently fallen off. Maintenance cleaned all joints, removed corrosion on the affected B-phase joint, and installed new bolting hardware. The inspection and repair activities were performed under a work order (WO).

In January of 2016, while conducting scheduled maintenance on a S/U transformer 6.9kV bus, a bus riser was identified to be significantly degraded based on an as-found visual inspection when the bus was opened for access. Further inspection was performed, and the following issues were found:

- Discoloration on bus insulation in all phases
- Wear and cracking in all phases potentially exposing copper bus at the worn-out insulation
- Signs of electric corona discharge and hot spots attacking the bus insulation
- Potentially corroded bus bars as corrosion byproducts found on bus insulators and bus joints.
- Dirt and rust flakes laying on the porcelain insulators contaminating the bus potentially creating a path for tracking
- Signs of water intrusion and excess moisture

The bus bars were removed for inspection and refurbishment. Based upon these inspections, which identified corrosion, loss of material, and marks of corona discharge, the bus bars were replaced, and new insulating material installed under a WO.

Currently, the existing 4.16kV and 6.9kV Non-Segregated Phase Bus are being replaced with cable bus under on-going modifications. The entire NSB modifications are scheduled to be complete prior to entering the SPEO.

In November 2015, the NRC completed a post-approval site inspection for License Renewal for Unit 1 in accordance with NRC IP71003; the comparable inspection for Unit 2 was completed in November 2017. The NRC reviewed selected procedures and records, observed activities, and interviewed personnel.

On the basis of the sample selected for review and in consultation with the Division of License Renewal in the Office of Nuclear Reactor Regulation, the NRC concluded PSL has completed the necessary commitments for operation into the period of extended operation.

One of the original license renewal commitments (No. 16) specified that the PSL would implement an enhanced Periodic Surveillance and Preventive Maintenance Program prior to the period of extended operation. This enhancement would include visual inspections of a representative sample of the bus bar insulation associated with the non-segregated phase buses. Additional inspections would then be performed every 10 years thereafter. The scope of the inspections would include age-related defects (e.g., discoloration, cracking) in bus bar insulation, interior of the bus ducts for moisture or dust/debris, as well as verifying the proper torque of the bus bar splice connection bolting.

The inspectors reviewed program basis documents, administrative and implementing procedures, self-assessments, and WOs to verify that the program was developed and executed with the criteria described in the LRA, and the corresponding NRC SER. The inspectors interviewed licensee personnel to discuss the scope, monitoring and trending, as well as the process for the generation of WOs. The inspectors reviewed a sample of WOs to verify that the licensee had completed the inspections and implemented appropriate corrective actions as described in the program, and associated correspondence to the NRC. There were no issues raised that were specific to the MEBs.

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 PSL Metal Enclosed Bus 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 PSL 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.2.3.42 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The PSL Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP for SLR. This AMP provides reasonable assurance that the intended functions of the metallic parts of electrical cable connections that are not subject to the EQ requirements of 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 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, will 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 AMP does not apply to high-voltage switchyard connections (>35 kV). Cable connections covered under the Environmental Qualification 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 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 PSL Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

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. PSL’s OE with connection reliability and aging effects should be adequate to demonstrate the AMP effectiveness of PSL Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, including the program’s capability to detect the presence or noting the absence of aging effects for electrical cable connections.

The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE.

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 Environmental Qualification Requirements at PSL:

In April of 2012, during a relay change for the main transformer coolers, transmission system operations protection and control (P&C) personnel experienced difficulty achieving a tight connection between the wires and the relay. One of the connecting wires was observed to be discolored, indicating that it had previously been overheated. A similar event occurred in February 2012 when the cooler controls were initially installed and tested by P&C. In that case, the relay failed and was replaced. P&C personnel completed an investigation of the relay wiring in the main transformer cooler control cabinets and tightened any connections as required and thermography was completed. No additional discolored wires were identified, and the one discolored wire identified was replaced. As a result, predictive maintenance performs routine quarterly and visual inspections on the Units 1 and 2 main transformers.

In August of 2012, routine thermography identified an increased temperature delta of 32°F on a capacitor terminal. The temperature reading was indicative of a loose connection. A repair was scheduled and thermography monitoring was increased to bi-monthly until the repair was completed.

In September of 2012, a cable connector on a wide range nuclear instrumentation drawer was found to be broken. A few days earlier tension on the cable was identified while the drawer was in the normal operating position. Upon further examination, the connector was found to be bent internally within the length of the connector body. The connection was temporarily taped up and the system was placed in a safe bypassed and powered down condition until the connection was repaired and restored. This was a design and human error issue, and not a cable connection aging issue.

In November of 2012, a crimper used on motor leads and jumpers failed calibration. The motor leads were re-lugged under a work order. This was a design and human error issue, and not a cable connection aging issue.

In February of 2013, predictive maintenance performed demand thermography on a battery charger during a load test. The battery charger loads and currents were recorded during the examination. A thermal anomaly was observed on a fuse (overheating). No other station battery chargers had shown this anomaly during their 18-month interval load tests. The fuse connections were cleaned and reconnected. Additionally, the degraded component, a loose lug, was re-torqued under the work order associated with the battery charger load test prior to releasing the maintenance clearance for the activity. This item is a direct example of the effectiveness of the PSL thermography program

In September of 2015, while performing calibration of a radiation monitor, the field cable and connector had issues. The cable associated with the detector seemed old and brittle and contained a bend at approximately 90 degrees with a degraded connector. An analysis was performed, and the problem with the radiation monitor did not indicate a bad cable or connector. A wire continuity check showed that the wire connections were performing satisfactorily. The cable and connector were determined to be acceptable for use as is and did not need replacement.

In October of 2016, during inspection of the 1B2 intake well area, a ground cable connection was found corroded and needed replacement The cable connection was replaced.

In May of 2016, a high resistance connection on a 120V #8 wire at the bottom of a 480V motor control center cubical was identified during a routine thermography inspection. The connection was 12 to 14°F higher than an adjacent wire. The connection in question had no visible effects of overheating. The connection was cleaned and re-tightened during the outage.

Although the PSL Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP for SLR, program health can be assessed by reviewing the 120VAC, 125V, 480V, 4160V, and 6.9 kV system health reports which are updated quarterly.

The system health reports for the 120VAC and 125V voltage systems have shown GREEN for a number of (at least 10 most recent) quarters with no discernable drop in ranking.

The 480V system health reports (4 most recent) quarters have shown WHITE statuses. A majority of the issues involved degraded mechanical interlocks, the position of the fire pump switch, relay and breaker modifications, and obsolete motor control center (MCC) compartments and components. No electrical cable connection issues were noted.

The 4160V system health reports for the last several years have shown WHITE and YELLOW statuses due mainly to relay and breaker modifications. No electrical cable connection issues were noted.

The 6.9 kV system health reports executive summary states that Unit 1 and Unit 2, 6.9 kV Switchgear/Breaker systems are green and STABLE.

The OE summarized above demonstrates that PSL 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 PSL are effective.

Program owner discussions were conducted in December of 2020 to discuss program effectiveness. Based on these discussions, there has been no new / unexpected aging effects experienced.

For all three NRC IP71003 Reviews; Level 1, License Renewal Aging Management Program Effectiveness Review, Phase 2 PSL, Unit 1 NRC Post-Approval Site Inspection for License Renewal, and Phase 2 PSL, Unit 2 NRC Post-Approval Site Inspection for License Renewal, there were no issues raised that were specific to electrical connections (metallic portions).

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 PSL Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification 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 PSL Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will provide reasonable assurance that the intended functions of the metallic parts of electrical cable connections will be maintained consistent with the CLB through the SPEO.

B.2.3.43 High-Voltage Insulators

Program Description

The PSL High-Voltage Insulators AMP is a new AMP. This AMP provides 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 AMP 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 provides 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, polymer, 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 OE with the specific type of insulator used (i.e., porcelain, polymer, toughened glass). 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 or peeling of silicone rubber sleeves for polymer insulators, or degradation of glazing on porcelain insulators. Visual inspections may be supplemented with infrared thermography inspections to detect high-voltage insulator reduced insulation resistance. Corona cameras may also be employed to detect early signs of corona emissions.

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 PSL High-Voltage Insulators AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.E7, "High-Voltage Insulators" as modified by SLR-ISG-2021-04-ELECTRICAL, "Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance."

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

In July 2013, the Diablo Canyon 500kV 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.

In addition, Columbia Generating Station experienced two flashover events in its transformer yard (in 1989 and 1990) when the cooling tower plume slumped over the Reactor Building and allowed the cloud to envelop the transformer yard for a period of time (with no wind or breeze). This moisture, combined with surface contamination (dust/dirt) allowed tracking to occur on surfaces of the porcelain, 500 kV high-voltage insulators (associated with a 115 kV transformer), and flashover conditions ensued.

Plant Specific Operating Experience

Considering this is a new AMP, there is limited OE. However, specific OE to insulators in the switchyard is as follows:

During Hurricane Irma in September of 2017, the switchyard experienced a buildup of salt on the insulators on the East and West buses. The East bus tripped and locked out and was unable to be restored without cleaning the salt from the insulators. The substation personnel reported that the West bus was also degraded due to salt on the insulators. Operations performed an evaluation of the Unit 1 and Unit 2 East/West buses and determined that Unit 1 should be conservatively shut down to facilitate the cleaning of the East bus and subsequent transfer to clean the West bus. The evaluation of Unit 2 identified that an alternate path existed and that a Unit shutdown was not needed to address the bus cleaning. The cause of the shutdown was due to a natural phenomenon beyond management control associated with the hurricane (Irma). The plant equipment functioned as expected, operator performance was without error, and the shutdown was uncomplicated.

System / program health reports are available on the FPL corporate portal under "ER dashboard". The new PSL High-Voltage Insulators AMP program health report is presently ascertained through the existing switchyard system health reports. 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 IP71003 Reviews; Level 1, License Renewal Aging Management Program Effectiveness Review Phase 2 PSL, Unit 1 NRC Post-Approval Site Inspection for License Renewal, and Phase 2 PSL, Unit 2 NRC Post-Approval Site Inspection for License Renewal, there were no issues raised that were specific to HV insulators.

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 PSL 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 PSL High-Voltage Insulators 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.2.3.44 Pressurizer Surge Line

Program Description

The PSL Pressurizer Surge Line AMP is an existing site-specific AMP that formerly was the PSL Pressurizer Surge Line Inspection Program (Fatigue). This AMP assesses fatigue based on the approach documented in the ASME Boiler and Pressure Vessel Code, Section XI, "Rules for In-service Inspection of Nuclear Power Plant Components, Non-Mandatory Appendix L Operating Plant Fatigue Assessment." This AMP incorporates an aging management inspection program that has been approved by the NRC. A flaw tolerance evaluation was performed specifically for PSL to assess the operability of the surge lines by using ASME Code Section XI Appendix L methodology and to determine the successive inspection schedule for the surge line welds with a postulated surface flaw. Two bounding locations applicable to both Units were evaluated in detail.

The two bounding weld locations of concern are the hot leg surge nozzle elbow-to-pipe weld and the adjacent elbow base material, which is a CASS material. Based on a comparison of geometry, material properties and applicable loads, the results of the detailed evaluation of the two bounding locations are also applicable to all other in-between pipe locations on the surge lines for both units.

The technical analysis supporting the postulated flaw tolerance evaluation for original License Renewal was provided by NRC letter to FPL (Reference ML16235A138), “PSL Plant, Unit Nos. 1 and 2 – Review of License Renewal Commitment for Pressurizer Surge Line Welds Inspection Program (CAC Nos. MF7026 and MF7027)”. The results of the circumferential crack growth for the hot leg surge nozzle elbow and weld are presented in the Table B-8 below.

Table B-8
Hot Leg Surge Nozzle Elbow and Weld Circumferential Crack Growth Results

Location	Stress Path	Crack Growth Results: Final Flaw Depth		Final Half Flaw Length		Allowable Operating Period
		[a/t]	(in.)	(in.)	(θ/π)	(months)
Base Metal	1	0.7481	0.9815	2.9445	0.163	432
	2	0.7241	0.9500	2.8500	0.159	624
	3	0.7327	0.9613	2.8839	0.160	384
	4	0.7394	0.9701	2.9103	0.162	252
Weld Metal	9	0.2808	0.3684	1.1052	0.062	720
	10	0.2608	0.3422	1.0266	0.057	720
	11	0.3285	0.4311	1.2933	0.072	720
	12	0.2807	0.3682	1.1046	0.061	720

<u>Notes for Table B-8</u>

1. The postulated initial flaw depth is 20 percent of the thickness (i.e., 0.201 inches) and the initial flaw length is 6 times its depth (i.e., 1.206 inches) per Appendix L guidelines.

2. A constant aspect ratio (a/l) of 1/6 is used in the crack growth analysis.

3. Flaw length based on Inner Diameter (ID)

4. The axial stresses are bounding hence only circumferential flaws were analyzed.

5. Per Appendix L, if the allowable operating period is equal or greater than 10 years, the successive inspection schedule shall be equal to the examination interval listed in the PSL ASME Section XI schedule of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B.2.3.1) AMP for the component.

Considering the allowable operating periods listed in Table B-8 above are greater than 10 years, per the guidelines of ASME Code Section XI Appendix L, Table L-3420-1, the applicable surge line welds for both units listed in Table B-9 below shall be examined by the end of each inspection interval listed in the schedule of inspection programs in IWB-2410 for the PEO. Note that welds with structural weld overlays (SWOL) have been screened out from the scope of analysis and inspections.

For SLR , the original flaw tolerance evaluation was revised and provided in the SIA Engineering Report No. 2001262.401 (Reference 1.6.47) to address eighty years of plant operation (end of the SPEO) using the ASME Code, Section XI, Appendix L methodology in the 2007 Edition with 2008 Addenda, which is the Code edition specified for PSL Units 1 and 2. The elbow adjacent to the hot leg surge nozzle was identified as the sentinel location for the surge line for both Units 1 and 2. As such, the revised Appendix L evaluation for SPEO was performed for the same bounding surge line location as the previous evaluation for PEO.

The revised Appendix L evaluation for SLR uses the same design inputs (i.e. surge line geometry, design transients, piping loads, etc.) and stress analysis as the previous Appendix L evaluation with the following technical changes:

1. For SLR, a separate evaluation of the CASS surge line base metal components was performed in support of the PSL Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP (Section B.2.3.6). As such, the scope of the revised Appendix L flaw tolerance evaluation for SLR is only for the weld metal of the surge line in support of PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1). The PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section B.2.3.1) does not inspect the CASS base metal, and thus only the surge line welds are inspected for Appendix L.

2. For fatigue crack growth in the weld metal, the initial flaw depth was determined from the applicable in-service inspection acceptance standard in ASME Code Section XI Table IWB-3410-1 per the Appendix L methodology [L-3212].

3. Projected 80-year fatigue cycles for PSL Units 1 and 2 were used to establish an estimate of the average number of cycles per year for calculating fatigue crack growth.

4. The latest crack growth curves for Type 304 and Type 316 stainless steels from ASME Code Case N-809 were used for fatigue crack growth. ASME Code Case N-809 has been approved by ASME and has been used in previous Appendix L evaluations for LR and SLR.

The revised Appendix L evaluation for SLR addressed the same stress paths in the weld of the bounding elbow adjacent to the hot leg surge nozzle as the previous Appendix L evaluation for the PEO. The revised evaluation results are shown in Table B-9 below and concluded that the allowable operating period was 47 years at the bounding surge line weld location (i.e., stress path 12 in the weld metal of the elbow adjacent to the hot leg surge nozzle). Furthermore, the bounding evaluation indicates that the allowable operating period for every surge line weld is 47 years from the time of the last inspection of that weld.

Table B-9
Crack Growth Results for Revised Appendix L Evaluation – 80 Years

Analysis Section Number (ASN) (Note 1)	Flaw Configuration (Note 2)	Appendix L Calculated Aspect Ratio	Initial Flaw Size, 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)
Stress Path P9	360-Degree Circumferential Flaw	N/A	0.1097	0.2195	0.2214	55
Stress Path P10	360-Degree Circumferential Flaw	N/A	0.1097	0.2194	0.2214	73
Stress Path P11	360-Degree Circumferential Flaw	N/A	0.1097	0.2178	0.2214	51
Stress Path P12	360-Degree Circumferential Flaw	N/A	0.1097	0.2172	0.2214	47

Notes for Table B-9

1. Stress paths are in the weld of the elbow adjacent to the hot leg surge nozzle. The location has been identified as the sentinel location for the surge line of both Units 1 and 2.

2. A 360-degree circumferential flaw bounds a semi-elliptical axial flaw and a semi-elliptical circumferential flaw.

Following the guidelines of Table L-3420-1 of Appendix L and IWB-2410 of ASME Code, Section XI, the successive inspection schedule for every surge line weld, including those for the pressurizer surge nozzle and hot leg surge nozzle at PSL Units 1 and 2, is 10 years from the time of the last inspection of that weld for SLR (refer to Table B-10 below). Therefore, for the SPEO, the effects of EAF for the PSL pressurizer surge line welds will continue to be managed by an inspection program consistent with the AMP approved by the NRC for the initial PEO.

Table B-10
Pressurizer Surge Line Welds Subject to EAF Inspections for SLR

Unit	Weld Number	Inspection Type and Frequency
Unit 1	RC-6-509 (12-inch branch to Safe End)	Weld with SWOL - AMP Not Applicable
	RC-108-FW-3 (Safe-End to Elbow)	Weld with SWOL - AMP Not Applicable
	RC-1-505-A (Elbow to Pipe)	Volumetric Once in 10-Year
	RC-1-505-B (Pipe to Pipe)	Volumetric Once in 10-Year
	RC-1-505-C (Pipe to Elbow)	Volumetric Once in 10-Year
	RC-108-FW-2 (Elbow to Pipe)	Volumetric Once in 10-Year
	RC-2-505-C (Pipe to Pipe)	Volumetric Once in 10-Year
	RC-108-FW-2000 (Pipe to Elbow)	Volumetric Once in 10-Year
	RC-108-FW-2001 (Elbow to Safe-End)	Volumetric Once in 10-Year
	S/C 004 (Surge line Nozzle to Safe-End Weld)	Volumetric Once in 10-Year
Unit 2	RC-301-771 (Nozzle to Safe End)	Weld with SWOL - AMP Not Applicable
	RC-108-FW-3 (Safe End to Elbow)	Weld with SWOL - AMP Not Applicable
	RC-106-751 (Elbow to Pipe)	Volumetric Once in 10-Year
	RC-113-751 (Pipe to Pipe)	Volumetric Once in 10-Year
	RC-107-751 (Pipe to Elbow)	Volumetric Once in 10-Year
	RC-108-FW-2 (Elbow to Pipe)	Volumetric Once in 10-Year
	RC-112-751 (Pipe to Pipe)	Volumetric Once in 10-Year
	RC-101-751 (Pipe to Elbow)	Volumetric Once in 10-Year
	RC-102-751 (Elbow to Pipe)	Volumetric Once in 10-Year
	RC-108-FW-1 (Pipe to Safe End)	Weld with SWOL - AMP Not Applicable
	RC-514-671 (Safe End to Nozzle)	Weld with SWOL - AMP Not Applicable

NUREG-2191 Consistency

The PSL Pressurizer Surge Line AMP is consistent with the ten elements of an aging management program described in NUREG-2192, Branch Technical Position A.1.2.3.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

PSL evaluates industry OE items for applicability per the FPL OE Program and takes corrective actions, when necessary. For example:

- NRC Information Notice (IN) 88-80: This IN provided Trojan plant experience regarding unexpected piping movement attributed to thermal stratification. No specific action or written response was required as a result of this IN.

- NRC Bulletin No. 88-11: Unexpected movement of the pressurizer surge line during inspections performed at the Trojan plant were observed at each refueling outage since 1982, when monitoring of the line movements began. During the most recent outage prior to this bulletin, the licensee found that in addition to unexpected gap closures in the pipe whip restraints, the piping contacted two restraints. It was also noted that the licensee for Beaver Valley 2 noticed unusual snubber movement and significantly larger-than-expected surge line displacement during power ascension. Unexpected piping movements are highly undesirable because of potential high piping stress that may exceed design limits for fatigue and stresses.

PSL completed all actions associated with this bulletin in conjunction with the Combustion Engineering Owners Group (CEOG). As noted in L-89-91 (Reference ML17222A738) and L-89-276 (ML17223A254), no gross discernable distress or structural damage was identified in the pressurizer surge line for either PSL Units 1 or 2. Therefore, no additional actions were required

Plant Specific Operating Experience

The Pressurizer Surge Line AMP does not have a program health report; however, in scope surge line welds are inspected in accordance with the PSL ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP under Augmented Programs within the ISI Program Plans. Therefore, the health reports for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP were reviewed for the last five years (2015-2020). The AMP had an Acceptable (Green) status for the entire five years except for the third and fourth quarters of 2018, which were White. However, none of the contributing factors to the White status were related to the pressurizer surge line.

A sample of the surge line welds have been examined ultrasonically in both PSL Units 1 and 2 during the first three in-service inspection intervals in accordance with the requirements of ASME Section XI, Subsection IWB. All in scope welds in the Unit 1 pressurizer surge line were examined in the ISI 4th Interval of Unit 1 except for one weld. To complete the 4^{th} Interval exams, the remaining Unit 1 weld is scheduled for examination during the refueling outage in the fall of 2025. All in scope welds in the Unit 2 pressurizer surge line were examined during the ISI 4th Interval of Unit 2 in 2017.

To date, no reportable indications have been found in the subject pressurizer surge line welds in either unit. The programmatic OE activities described in relevant station procedures ensure the adequate evaluation of OE on an ongoing basis to address age-related degradation and aging management for the PSL Pressurizer Surge Line AMP.

Program Assessments and Evaluations

2016 – Unit 1 Post-Approval Site Inspection for License Renewal, Inspection Report

The NRC completed a post-approval site inspection for license renewal (LR) for Unit 1. The proposed program for managing EAF of the Unit 1 and 2 pressurizer surge lines was submitted to the NRC on October 29, 2015. The inspectors noted that the proposal detailed the intent of PSL to utilize the ASME, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP to manage the recurring inspections, and the associated evaluations for any flaws noted. However, at the time of this inspection, a safety evaluation report accepting this program had not yet been issued by the NRC. This was resolved via issuance of the SER, which accepted the program for managing EAF of the pressurizer surge lines.

2017 – Focused Self-Assessment PSL Unit 2 License Renewal Implementation

This self-assessment focused on the readiness for the NRC LR Implementation IP71003 Phase II inspections scheduled for October 2017. LR implementation was determined to be on track but identified some existing findings that needed to be closed prior to the August 28, 2017 NRC Phase II inspection; however, none of the findings involved the pressurizer surge line. With regard to the Pressurizer Surge Line AMP, the self-assessment stated that the NRC had approved the program via the SER issued 10/13/2016 and that all assignments had been completed.

2020 – License Renewal Effectiveness Review

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in January 2021 and no findings related to the PSL Pressurizer Surge Line AMP were identified.

The PSL Pressurizer Surge Line 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 PSL Pressurizer Surge Line AMP provides 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.

APPENDIX C

LICENSEE SPECIFIC ACTIVITIES RELATIVE TO RVI

PSL NUCLEAR PLANT UNITS 1 AND 2

SUBSEQUENT LICENSE RENEWAL APPLICATION

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C.1.0 Purpose

The existing St. Lucie Nuclear Plant (PSL) Reactor Vessel Internals aging management program (AMP) is based on Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) Topical Report No. 3002017168, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A)," issued June 2020 (Reference ML20175A112). The original implementation of the program was approved by the staff (Reference ML18071A002) and was developed in accordance with MRP-227-A. PSL has continued to update the program as industry guidance is released and is currently implementing the most recent guidance (MRP-227 Revision 1-A).

Because the guidelines of MRP-227 Revision 1-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, as modified by Interim Staff Guidance for Reactor Vessel Internal Components for Pressurized-Water Reactors provided in SLR-ISG-2021-01-PWRVI (Reference ML20217L203), 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 PSL subsequent license renewal (SLR) RVI gap analysis uses the most recent guidelines provided in MRP-227 Revision 1-A as the baseline to address an 80-year operating period, consistent with the interim staff guidance. MRP-227 Revision 1-A provides updates based on Revision 1 of the NRC Safety Evaluation (SE) for MRP-227 Revision 0 (Reference ML11308A770) and includes operating experience and new knowledge gained from materials testing, modeling, and research.

To address the SPEO, the guidelines in MRP-227 Revision 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
- 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
- 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 (ML19081A057)

EPRI recommendations in MRP 2018-022 were drafted prior to the publication of MRP-227 Revision 1-A, and as such references MRP-227-A and MRP-227 Revision 1. However, the recommendations in MRP 2018-022 implement the screening and threshold values of MRP-175 Revision 1, and the screening categorization and ranking of MRP-191 Revision 2. To capture any changes which occurred during the SE process and inform PSL implementation of the guidance, this gap analysis compares the MRP 2018-022 recommended table entries against both MRP-227-A and MRP-227 Revision 1-A. MRP-227 Revision 1-A, as modified by the recommendations in MRP 2018-022, 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 as of 2017.

The following sections apply the current industry body of work identified above relevant for 80-years. The resulting changes will supplement the current guidance and provide aging management of the PSL Units 1 and 2 reactor vessel internals for an 80-year operating period.

C.2.0 Applicability of MRP-227 Revision 1-A for 80 Years of Operation

The engineering evaluations, assessments and categorization for inspection performed in MRP-227 Revision 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 Revision 1-A. The baseline inspection categories are altered based on the screening, failure modes, effects, and criticality analysis (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 PSL Units 1 and 2 in the NRC SE of the initial license renewal reactor vessel internals aging management program (Reference ML18071A002) 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 ≤ 68 Watts/cm^3
- Average core power density < 110 Watts/cm^3
- Active fuel to fuel alignment plate distance > 12.4 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 a fixed thermal power level 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 Combustion Engineering-designed plants. To obtain representative dose projections with a reasonable amount of added conservatism, dose projections were generated using a model for one specific 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 results above and below the active fuel, and
- A best-estimate power shape that with 30 percent margin added was more limiting in the radial direction.

A composite dose map was generated using the maximum value of the two dose projections above for each mesh cell in the neutron transport calculation. The above assumptions (a) through (d) were validated for PSL Units 1 and 2 in the NRC SE of the initial license renewal reactor vessel internals aging management program (Reference ML18071A002) and low leakage fuel management parameters are verified for every cycle. As such, the dose projection used is demonstrated to be applicable to PSL. With respect to item (c), note that the Unit 1 core support barrel expandable plugs and patches, discussed in Section 4.7.3, were developed and the repair method was analyzed by the original vendor. The PSL Units 1 and 2 site specific fluence model is consistent with the guidance of Regulatory Guide 1.190 and the methodology described in WCAP-18124-NP-A (Reference ML18204A010) that was approved by the NRC.

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 Revision 1-A was not available at the time, MRP-227 Revision 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. In some cases, the recommendations in the MRP 2018-022 table excerpts presented below were predictions of changes which would be made by MRP-227 Revision 1-A. In these cases, PSL will continue to implement the guidance in MRP-227 Revision 1-A. Each table is followed by a summary of the changes for each component and how they will be implemented at PSL.

MRP 2018-022 Expected New Entries for Combustion Engineering Primary Components

Primary Item	Applicability	Effect (Mechanism)	Expansion Link (Note 1)	Examination Method / Frequency	Examination Coverage
Core Shroud Assembly (Welded) Core shroud tie rods	All plants with core shroud tie rods	Cracking (IASCC, Fatigue), Loss of Material (Wear), Distortion (Void Swelling) Aging management (IE and ISR/IC)	Welded Core Shroud Assembly	Visual (VT-3) examination no later than 2 refueling outages from the beginning of the subsequent license renewal period. Subsequent examinations during every refueling outage.	Examination of the top end of 100% of the core shroud tie rods. Top-down and side views of each tie rod must be obtained.
Alignment and Interfacing Components Core stabilizing lug shim bolts	All plants	Cracking (SCC), Loss of material (Wear)	None	Visual (VT-3) examination no later than 2 refueling outages from the beginning of the subsequent license renewal period. Subsequent examinations on a ten-year interval.	All core stabilizing lug shim bolts.

Core Shroud Tie Rods

The addition of the core shroud tie rods in the Primary Components inspection category is unique to MRP 2018-022 and has not previously appeared in NRC approved guidance. This new entry is applicable to PSL for the subsequent period of extended operation.

PSL Actions

This guidance is applicable to the subsequent period of extended operation. PSL will incorporate the guidance as presented in MRP 2018-022 with respect to the core shroud tie rods.

Core Stabilizing Lug Shim Bolts

The addition of the core stabilizing lug shim bolts in the Primary Components inspection category is unique to MRP-2018-022 and has not previously appeared in NRC approved guidance. This new entry is applicable to PSL for the subsequent period of extended operation.

PSL Actions

This guidance is applicable to the subsequent period of extended operation. PSL will incorporate the guidance as presented in MRP 2018-022 with respect to the core stabilizing lug shim bolts.

MRP 2018-022 Expected New Entries for Combustion Engineering Expansion Components

Item	Applicability	Effect (Mechanism)	Primary Link	Examination Method	Examination Coverage
Upper Internals Assembly Fuel alignment plate (Expansion only after entering SLR period)	All plants with welded core shrouds assembled in two vertical sections	Cracking (IASCC, Fatigue), Loss of material (Wear), Aging management (IE)	Core Support Barrel Assembly: Lower cylinder girth welds	Enhanced visual (EVT-1) examination. Subsequent examination on a ten-year interval*	100% of accessible surfaces.*

* The inspection requirement for the fuel alignment plate is analogous to the current requirement for the Westinghouse-design UCP in MRP-227-A. The inspection technique requirement for the UCP was reduced in MRP-227, Revision 1 and justified in responses to RAIs on MRP-227, Revision 1. Once the NRC safety evaluation is complete, the resulting reduced inspection requirements of the Westinghouse-design UCP can be substituted here for the fuel alignment plate.

As the NRC safety evaluation has been completed, the recommendation is now to perform a visual (VT-3) examination with reinspection every 10 years following initial inspection. The examination coverage is required to be a minimum of 25 percent of core side surfaces if no significant indications are found. However, the examination acceptance criteria require that additional coverage must be achieved in the same outage if significant flaws are found.

Additionally, the primary link for this component is the middle girth weld instead of the lower cylinder girth weld. This is consistent with the changes to the primary and expansion components which occurred during the NRC review of MRP-227 Revision 1.

Fuel Alignment Plate

The addition of the fuel alignment plate in the Expansion Components inspection category is unique to MRP 2018-022 and has not previously appeared in NRC approved guidance. Adding the fuel alignment plate as an expansion component is applicable to PSL for the subsequent period of extended operation. The examination method and examination coverage should be made consistent with the Westinghouse-design UCP.

PSL Actions

This guidance is applicable to the subsequent period of extended operation. PSL will incorporate the guidance, consistent with the examination method, examination coverage, and examination acceptance criteria presented for the Westinghouse-design UCP in MRP-227 Revision 1-A. This augmentation of the guidance presented in MRP 2018-022 is consistent with the note provided.

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<u>MRP 2018-022 Expected Revised Entries for Combustion Engineering Primary Components</u>

Primary Item	Applicability	Effect (Mechanism)	Expansion Link	Examination Method / Frequency	Examination Coverage
Core Shroud Assembly (Welded) Assembly	Plant designs with core shrouds assembled in two vertical sections	Distortion (Void Swelling), as evidenced by measurable separation between the upper and lower core shroud segments or by shifting of the segments relative to one another or the core support plate Aging Management (IE)	None	Visual (VT-1) examination no later than 2 refueling outages from the beginning of the license renewal period. Subsequent examinations on a ten-year interval.	100% of the horizontal seam between the upper and lower core shroud segments. 100% of the seam between the lower core shroud segment and the core support plate.
Core Support Barrel Assembly Lower cylinder girth welds*	All plants	Cracking (SCC, IASCC) Aging Management (IE)	Lower cylinder axial welds Fuel alignment plate (Plant designs with core shrouds assembled in two vertical sections only)	Enhanced visual (EVT-1) examination no later than 2 refueling outages from the beginning of the first license renewal period. Subsequent examinations on a ten-year interval	100% of the accessible surfaces of the lower cylinder welds.

* Under MRP-227, Revision 1, this component would be the Core Support Barrel Assembly Middle Girth Weld (MGW) with expansions to the middle axial weld (MAW) and lower axial weld (LAW). Per the responses to NRC RAIs on MRP-227, Revision 1, the core support columns could also become an expansion to the MGW. Once MRP-227, Revision 1 has received a safety evaluation with acceptance of these changes, revisions to the naming of the Primary and Expansion components for the MRP-227-A "lower cylinder girth welds" provided in the approved version of MRP-227, Revision 1 should be substituted here.

As the NRC safety evaluation has been completed, the middle girth weld is the appropriate primary component with expansion links to the middle axial weld, lower axial weld, and core support columns. Consistent with the MRP 2018-022 recommendation to include the fuel alignment plate as an expansion component, it is also linked to the middle girth weld. The examination method, frequency, and coverage defined in MRP-227 Revision 1-A for the middle girth weld is also appropriate.

Core Shroud Assembly

The revisions to the core shroud assembly in the Primary Components inspection category is not unique to MRP 2018-022. These revisions represent predictions of changes which were ultimately made in MRP-227 Revision 1-A. The guidance in MRP-227 Revision 1-A is appropriate to implement.

PSL Actions

PSL will continue to implement the NRC approved changes within MRP-227 Revision 1-A.

Lower Cylinder Girth Welds

The addition of the fuel alignment plate as an Expansion component to the lower cylinder girth welds is unique to MRP 2018-022 and has not previously appeared in NRC approved guidance. Adding the fuel alignment plate as an expansion component is applicable to PSL for the subsequent period of extended operation. Consistent with the note in MRP 2018-022, the primary and expansion components for this link should be consistent with the guidance in MRP-227 Revision 1-A.

PSL Actions

PSL will continue to implement the NRC approved changes within MRP-227 Revision 1-A and add the fuel alignment plate to the expansion link.

MRP 2018-022 Expected Revised Entries for Combustion Engineering Examination Acceptance and Expansion Criteria

Primary Item	Applicability	Examination Acceptance Criteria	Expansion Link(s)	Expansion Criteria	Expansion Item Examination Acceptance Criteria
Core Support Barrel Assembly Lower cylinder girth welds*	All plants	Visual (EVT-1) examination. The specific relevant condition is a detectable crack-like surface indication.	Lower cylinder axial welds Fuel alignment plate (Plant designs with core shrouds assembled in two vertical sections only)	The confirmed detection and sizing of a surface-breaking indication >2 inches in length in a lower cylinder girth weld shall require an EVT-1 examination of all accessible lower cylinder axial welds by the completion of the next refueling outage. (Applicable only after entering the SLR period) The confirmed detection and sizing of a surface-breaking indication >2 inches in length in a lower cylinder girth weld shall require an EVT-1 of the fuel alignment plate within the next three refueling outages.	The specific relevant condition for the expansion lower cylinder axial welds is a detectable crack-like surface indication. The specific relevant condition is a detectable crack-like surface indication.

* Under MRP-227, Revision 1, this component would be the Core Support Barrel Assembly Middle Girth Weld (MGW) with expansions to the middle axial weld (MAW) and lower axial weld (LAW). Per the responses to NRC RAIs on MRP-227, Revision 1, the core support columns could also become an expansion to the MGW. Once MRP-227, Revision 1 has received a safety evaluation with acceptance of these changes, revisions to the naming of the Primary and Expansion components for the MRP-227-A "lower cylinder girth welds" provided in the approved version of MRP-227, Revision 1 should be substituted here.

As the NRC safety evaluation has been completed, the middle girth weld is the appropriate primary component with expansion links to the middle axial weld, lower axial weld, and core support columns. Consistent with the MRP 2018-022 recommendation to include the fuel alignment plate as an expansion component, it is also linked to the middle girth weld.

The expansion criteria for the fuel alignment plate are consistent with those identified for the Westinghouse-design UCP in MRP-227 Revision 1-A as follows;

The confirmed detection and sizing of a surface-breaking indication with a length greater than two inches in the middle girth weld shall require inspection of the fuel alignment plate within the next three refueling outages. If an indication is found in this inspection of the fuel alignment plate, the examination coverage shall be expanded to 100 percent of the accessible surface of the core-side surface of the fuel alignment plate during the same outage.

The expansion acceptance criteria for the fuel alignment plate are consistent with those identified for the Westinghouse-design UCP in MRP-227 Revision 1-A as follows;

The specific relevant conditions for the inspection of the fuel alignment plate are broken or missing parts of the plate.

Lower Cylinder Girth Welds

The addition of the fuel alignment plate as an Expansion component to the lower cylinder girth welds is unique to MRP 2018-022 and has not previously appeared in NRC approved guidance. Adding the fuel alignment plate as an expansion component is applicable to PSL for the subsequent period of extended operation.

Consistent with the note in MRP 2018-022, the primary item, expansion links, expansion criteria, and expansion item examination criteria should be consistent with the guidance in MRP-227 Revision 1-A. In the case of the newly added fuel alignment plate, the expansion criteria and expansion item examination acceptance criteria should be consistent with the Westinghouse-design UCP.

PSL Actions

PSL will continue to implement the NRC approved changes within MRP-227 Revision 1-A and add the fuel alignment plate as an expansion link for the middle girth weld using the expansion criteria and expansion item examination acceptance criteria from the Westinghouse-design UCP.

C.3.0 Operating Experience

PSL 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 Revision 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.

C.4.0 Conclusions

Two new components are added to the Primary Components inspection category in addition to those identified in MRP-227 Revision 1-A (core shroud tie rods and core stabilizing lug shim bolts) and one new component is added to the Expansion Components inspection category (fuel alignment plate) consistent with the guidance in MRP 2018-022.

The conclusions of this gap analysis will be superseded if an NRC-approved version of MRP-227 that addresses 80 years of operation becomes available, consistent with Commitment 10 of Table 19-3 in Appendix A.

C.5.0 References

C.5.1. EPRI Technical Report No. 3002010268, MRP-175, Revision 1, Materials Reliability Program: PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values, October 2017

C.5.2. 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, November 2018

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 PSL SLRA and Technical Specifications, no Technical Specifications changes are being submitted with this Application.